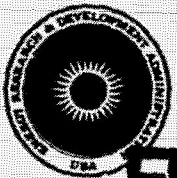


JUNE, 1976

THE COST OF ENERGY FROM UTILITY-OWNED SOLAR ELECTRIC SYSTEMS

A REQUIRED REVENUE METHODOLOGY FOR ERDA/EPRI EVALUATIONS



EPRI

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JUNE, 1976

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PREFACE

One of the major needs in energy system planning is for standard, consistent methods of establishing and combining relevant parameters in order to support the comparison of different systems and the decision processes which must ensue. This requirement is strongly felt in the field of economic analysis of energy systems. Prior studies of electric power plant costs have appeared inconsistent and even misleading because of their different economic approaches and choices of financial parameters. As a result, correlation of these studies, and comparison of the plants and technologies to which they refer, has been difficult or impossible.

The methodology presented in this document is intended as a first step to relieve the problem of comparative evaluation of technologies and plant concepts in the important developing area of solar energy. It is predicated upon private and municipal utility ownership, and to that end includes approaches, data, and techniques provided by the Electric Power Research Institute. Further inputs were provided by the Energy Research and Development Administration, which, through the Low-Cost Silicon Solar Array Project at the Caltech Jet Propulsion Laboratory, sponsored development of the methodology. Other laboratories and members of the utility and utility-equipment industries have also provided inputs.

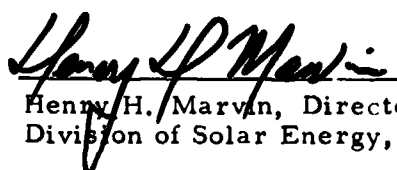
This methodology addresses only those costs that are incurred as direct results of purchasing, installing, and operating an energy system, and derives the energy "price" necessary to recover those costs. A utility adoption decision will require information additional to that provided by this method; however, the model presented will fulfill the important function of providing reliable information regarding the relative ranking of energy system options in a consistent manner. All on-going and future studies by ERDA and EPRI solar energy system contractors will use the method; other energy system analysts are encouraged to do so as well. ERDA is also planning to develop and release a companion model covering user-owned systems.

The methodology described in this document was developed principally at the Caltech Jet Propulsion Laboratory. Mr. J. W. Doane was the principal author and developer of the algorithms and explanations, with support provided by Mr. R. G. Chamberlain. The original leveled fixed-charge approach was provided by Mr. P. B. Bos of EPRI and integrated with the JPL life-cycle costing approach by Dr. R. P. O'Toole of JPL. Mr. P. D. Maycock of ERDA established the need and support for broadening the application of the methodology from photovoltaic conversion systems to all solar energy system options. The funding support and program management of the activity was provided by Dr. M. B. Prince, Chief, ERDA Photovoltaic Branch and Dr. L. M. Magid, Program Manager, ERDA Photovoltaic Branch.

The ERDA Division of Solar Energy and the EPRI Solar Program intend to make this methodology a required standard assessment tool and invite comments regarding its application.



Piet B. Bos, Program Manager
Solar Energy, EPRI



Henry H. Marvin, Director
Division of Solar Energy, ERDA

FOREWORD

This methodology was developed to serve a two-fold purpose -- to provide energy system engineers with a conceptually sound economic assessment tool, and to assure the ability to make "common denominator" comparisons among the results of distinct system studies. The authors appreciate the efforts of Mr. H. L. Macomber of the JPL Low-Cost Silicon Solar Array (LSSA) Project in articulating the need for such a standard approach and for providing the technical management support to carry out the effort. We wish also to thank Mr. R. G. Forney, LSSA Project Manager, for releasing from immediate project responsibilities the resources necessary to complete this work.

The funding support of ERDA and the institutional support of EPRI are gratefully acknowledged. Mr. P. B. Bos of EPRI convinced us of the advantages of the fixed charge rate approach, and provided valuable assistance with respect to the business and technical environments of electric utilities. Dr. R. P. O'Toole performed the initial integration of Mr. Bos's inputs with JPL's life-cycle costing approach. Mr. R. G. Chamberlain bore the major responsibility for executing Appendices A and B, and also served as principal collaborator on the document as a whole. Mr. P. D. Maycock of ERDA provided information necessary for the material to apply to the various solar energy technologies, and served as a valuable clearing house for comments and inputs from outside reviewers. The following organizations have followed the development and this methodology with interest, and provided valuable assistance in reviewing and commenting on the method during its several stages of evolution:

The Aerospace Corporation
General Electric Company
Midwest Research Institute
MITRE Corporation
Oak Ridge National Laboratory
Sandia Laboratories
Southern California Edison Company
Spectrolab, Incorporated
Westinghouse Corporation

James W. Doane
Jet Propulsion Laboratory

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ABSTRACT

This methodology calculates the electric energy busbar cost from a utility-owned solar electric system. This approach is applicable to both publicly- and privately-owned utilities. Busbar cost represents the minimum price per unit of energy consistent with producing system-resultant revenues equal to the sum of system-resultant costs. This equality is expressed in present value terms, where the discount rate used reflects the rate of return required on invested capital. Major input variables describe the output capabilities and capital cost of the energy system, the cash flows required for system operation and maintenance, and the financial structure and tax environment of the utility.

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SECTION I

INTRODUCTION

The objective of this methodology is to provide a standard technique for the production of reliable rank orderings of alternative utility-owned solar energy system designs in terms of their cost-effectiveness in producing energy. There are several constraints applicable to the model chosen to accomplish this purpose. First, the method should be specific enough for contractor implementation with a minimum of detailed direction from the appropriate program office, yet sufficiently flexible to permit meaningful comparisons of systems with significant technical and economic differences. Second, the method should incorporate enough detail to produce realistic figures of merit for the cost-effectiveness of systems in particular applications. At the same time, the answers should not depend on minute differences in particular installations. Third, the basic methodology should be consistent with conventional business practices for evaluating the cost of projects. Since the basic intent is to identify those systems with the greatest potential for commercialization, it is important that the rankings produced be relevant to utilities as potential buyers of solar energy systems. Fourth, the methodology should be kept to a level that requires neither computer software nor expertise in financial management, and allows the user to follow intuitively the progression of the analysis from inputs through intermediate results to final output. Finally, the methodology must, if it is to be a standard, resolve several ambiguities that frequently characterize projections of system costs. Specifically, the methodology must:

- i. express cost in terms of a standard unit (i.e., dollars of constant purchasing power).
- ii. incorporate a systematic treatment of interest during construction.
- iii. clearly distinguish between a measure of cost which applies only to a single year, and a measure which summarizes cost over the entire system lifetime.

This methodology addresses only those costs that are incurred as direct results of purchasing, installing, and operating an energy system, and derives

the energy "price" necessary to recover those costs. A utility adoption decision will require additional information regarding, e.g., the interaction of solar energy systems with utility-wide capacity, transmission, and load characteristics; cost and availability of non-solar energy options; and further considerations of the utility's taxation and regulatory environments. In each case, the adoption decision will be influenced by expectations of future conditions, as well as by current conditions. For these reasons, the present methodology should be viewed as a screening tool for comparative assessment of energy systems, and not as a complete framework for venture analysis by utilities, nor as a means to estimate the absolute cost effectiveness of utility-owned solar energy systems.

This document consists of five main body sections and five appendices. Section I is this Introduction. Section II, Approach, delineates the analysis problem, enumerates some possible solutions to that problem, and relates the selected model to the broader area of discounted cash flow analysis. Section III, Methodology, is a procedures-oriented explanation of the calculation and application of the annualized fixed charge approach to computing busbar energy cost. Section IV, Cost Account Structure, explains the interface necessary between the analytical method and the cost data describing the energy systems, and identifies the basis for the account structure selected. Appendix A is a comprehensive glossary of terms and symbols used in this document. Appendix B is an extensive treatment of the intuitive content of the model, and contains rigorous derivations of the major equations. Appendix C is an illustration of a cost account structure developed for a solar thermal power plant. Appendix D is an illustration of the methodology, in the form of a hypothetical numerical example. Appendix E presents a generalization of the model to include two major forms of tax preference not treated in the main text.

SECTION II

APPROACH

There are several widely accepted capital budgeting techniques for ranking the commercial attractiveness of alternative investment projects. In general, these approaches compare the expected revenue and expense cash flows (both corrected for the influence of the timing of dollar flows) and provide criteria both for accept/reject decisions and for ranking acceptable projects. The present analysis is somewhat different from a conventional capital budgeting problem in that all the projects considered are utility-owned energy systems, and that the immediate benefits in each case consist of energy outputs measurable in common physical units. Given this built-in normalization of the benefits side, it is possible to rank systems on the basis of "cost per unit of benefit," which in this case is equivalent to cost per unit of energy.

The basic approach of the present model is to derive an estimate of those costs incurred by an investor-owned utility as a result of purchasing, installing, and operating a given solar energy system (excluding transmission and distribution costs). These costs, suitably aggregated over the system lifetime and converted to a yearly basis, are divided by the expected yearly energy output of the specific system. The result is an estimate of the busbar cost of energy from the system: that is, if the system were to produce exactly its expected output, and if that output were "sold" at a price equal to the estimated cost above, the resultant revenues would exactly recover the full costs of the system over its lifetime, including a return on the investments of stockholders and creditors. Alternatively, the estimated cost of energy is the revenue required per unit of energy output if the system is to pay for itself.

The full costs referred to above include a compensation to investors for the opportunity cost of their committed funds, and thus the model is intrinsically a discounted cash flow approach. It differs from a conventional venture analysis, however, in that the revenue stream is derived rather than input. Required revenue per unit is found as the minimum energy price consistent with recovering all costs.

The required revenue approach can be explained in terms of standard concepts from capital budgeting theory. First, the project represented by the energy system is constrained to have a net present value of zero. Alternatively, the required revenue is defined as that which gives the energy system project an internal rate of return exactly equal to the cost of money to the owning utility. A third statement of the essence of the model is in terms of life-cycle cost, defined as the present value, as of a specified point in time, of all of the costs incurred as direct results of purchasing, installing, and operating the system. The model solves for a revenue stream which has a present value equal to the life-cycle cost of the system.

The operation of computing the present value of a distribution of cash flows "collapses" that distribution to a single number. Present value can thus be regarded as a measure which summarizes a given cash flow distribution, and for a given discount rate and index period, the value of that measure is unique. The converse does not hold, however, and there are an infinite number of possible cash flow distributions with the same present value (even for a constant discount rate and index period). Thus, the model requirement that the revenue flow have a present value equal to system life-cycle cost does not imply a unique distribution of revenue flows. The revenue per unit measure selected for this methodology is a levelized energy cost, a single number representing an average of a distribution of varying charges. This average relationship is illustrated in Fig. 1. The horizontal line at $\overline{\text{BBEC}}$ represents the levelized busbar energy cost in mills per kilowatt-hour. The curved line labeled BBEC_t represents a hypothetical series of growing charges. $\overline{\text{BBEC}}$ is "typical" of the growing distribution in that it represents a uniform distribution which, over the same time interval (y_{co} to $y_{\text{co}} + N$), has the same present value. For this to be true, the two shaded areas must also have equal present values. (The areas shaded are not equal geometrically, reflecting greater discounting of later year revenues.) Thus the levelized charge represents an overcharge (relative to a growing distribution) in early years and an undercharge in later years. In present value terms, however, the two approximations cancel one another, so that the distribution of constant charges has exactly the correct present value. An important implication of Fig. 1 is that, for purposes of representative comparisons, energy costs from different systems must both be levelized. At a more general level, the conceptual advantages of this

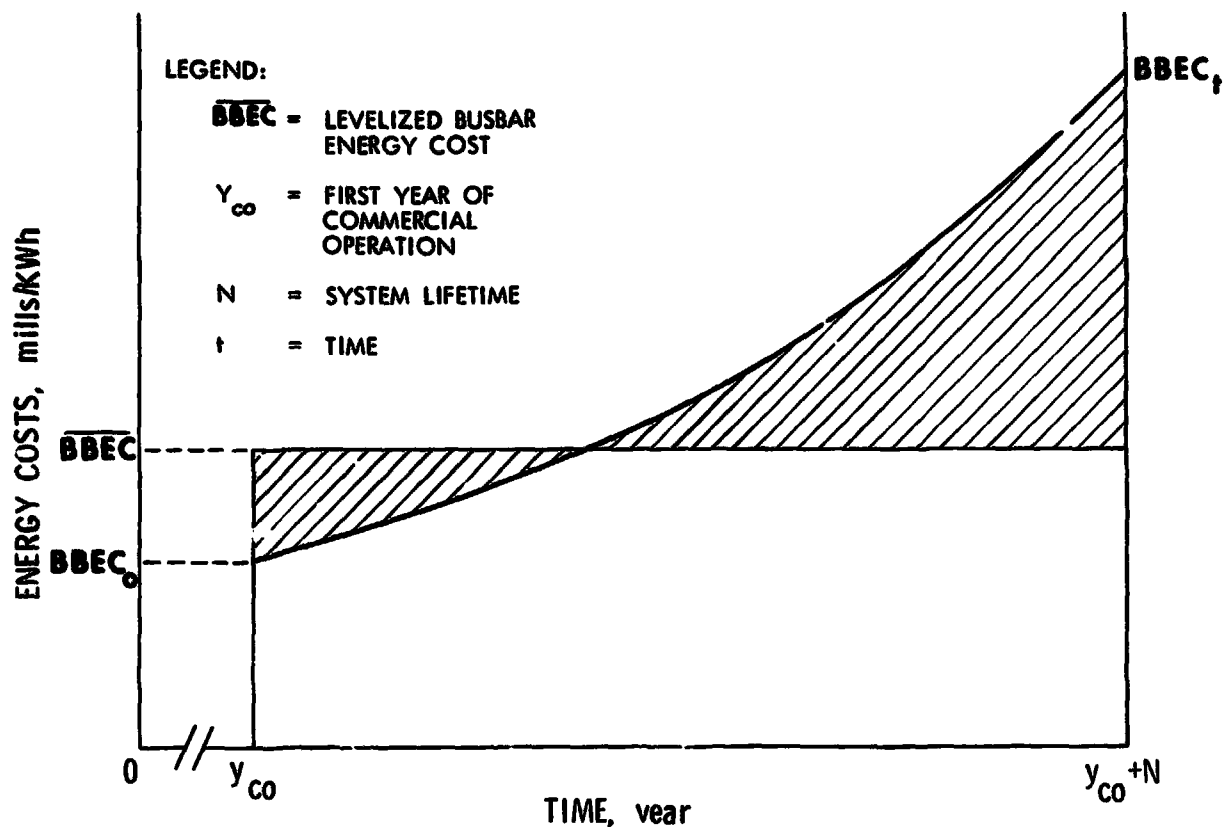


Fig. 1. Comparison of Levelized Energy Cost with Growing Energy Costs.

approach for system comparisons are fully realized only when the standard method is applied to all systems involved.

A frequent source of confusion in interpreting system cost projections concerns the real value of the dollars in which those projections are denominated. For the purposes of this methodology, all cost inputs are to be expressed in terms of current dollars (i.e., there should be no prior adjustment by contractors for cost escalation). Escalation adjustments are "built in" to the algorithms defined below (once the relevant rates of escalation are specified), and therefore occur internally. Similarly, the methodology automatically calculates interest during construction, and that interest should not be included in the input values for capital costs.

Some further qualification is necessary with respect to the extent to which the model normalizes for technical differences among energy systems.

Two important areas will be discussed: system lifetime and system/utility interaction.

Systems compared with this methodology must have the same operating lifetime. This is a consequence of the annualization of the energy cost into a stream of payments that is constant throughout the lifetime. This constraint is not expected to have severe consequences in the comparison of alternative solar electric energy systems. Any comparison between two systems will thus require a common time basis, including a common year for cost comparisons and a common operating period.

Interaction of a solar energy system with utility-wide capacity and load characteristics can be an important source of indirect costs and/or benefits to the owning utility. Quantification of these indirect effects requires utility-wide analysis, and is clearly beyond the scope of this model. Thus strictly valid comparisons of energy costs are restricted to systems with comparable effects on the utility as a whole. To the extent that outside estimates of indirect costs or benefits are available, they can be used to extend the model results to cover the complete cost of energy.

SECTION III

METHODOLOGY

A. OVERVIEW

The purpose of this Section is to provide a "user's guide" to the model by explaining how the parts fit together, and how the calculation of energy cost for a particular system should be performed.¹ This explanation is built around Fig. 2, which displays the general structure of the model, as well as a detailed flow of specific inputs through the key equations to final output. The parts of Fig. 2 will be addressed in roughly a left-to-right sequence, beginning with the input data. This model produces a single output — a number representing the cost per unit of energy from a utility-owned solar energy system. This cost is found by dividing an annualized measure of total system-resultant costs by the constant annual energy output expected from the system. It can be interpreted as the minimum price at which energy from the system could be sold, and still produce revenues sufficient to recover all system-resultant costs.²

Inputs to the model consist of technical and cost data describing the energy system to be analyzed, escalation rates applicable to various categories of system-resultant cost, and pertinent financial characteristics of the owning utility. The system description data details the basic costs of system purchase, installation, and operation, and defines system performance. The escalation rates determine the conversion of those costs to current year dollars over the analysis period. The utility description data influences the direct costs of system ownership and, together with the other inputs and basic model relations, determines the cost of energy.

¹ Appendices A, B, and D are closely related to this Section: Appendix A contains a glossary of terms; Appendix B contains a rigorous and detailed exposition of the methodology; Appendix D contains a step-by-step numerical illustration.

² Since transmission and distribution costs are excluded, the minimum price at which energy could be sold to consumers would, of necessity, be higher than that indicated by the model. The model output should be interpreted as that portion of the retail price attributable to generation.

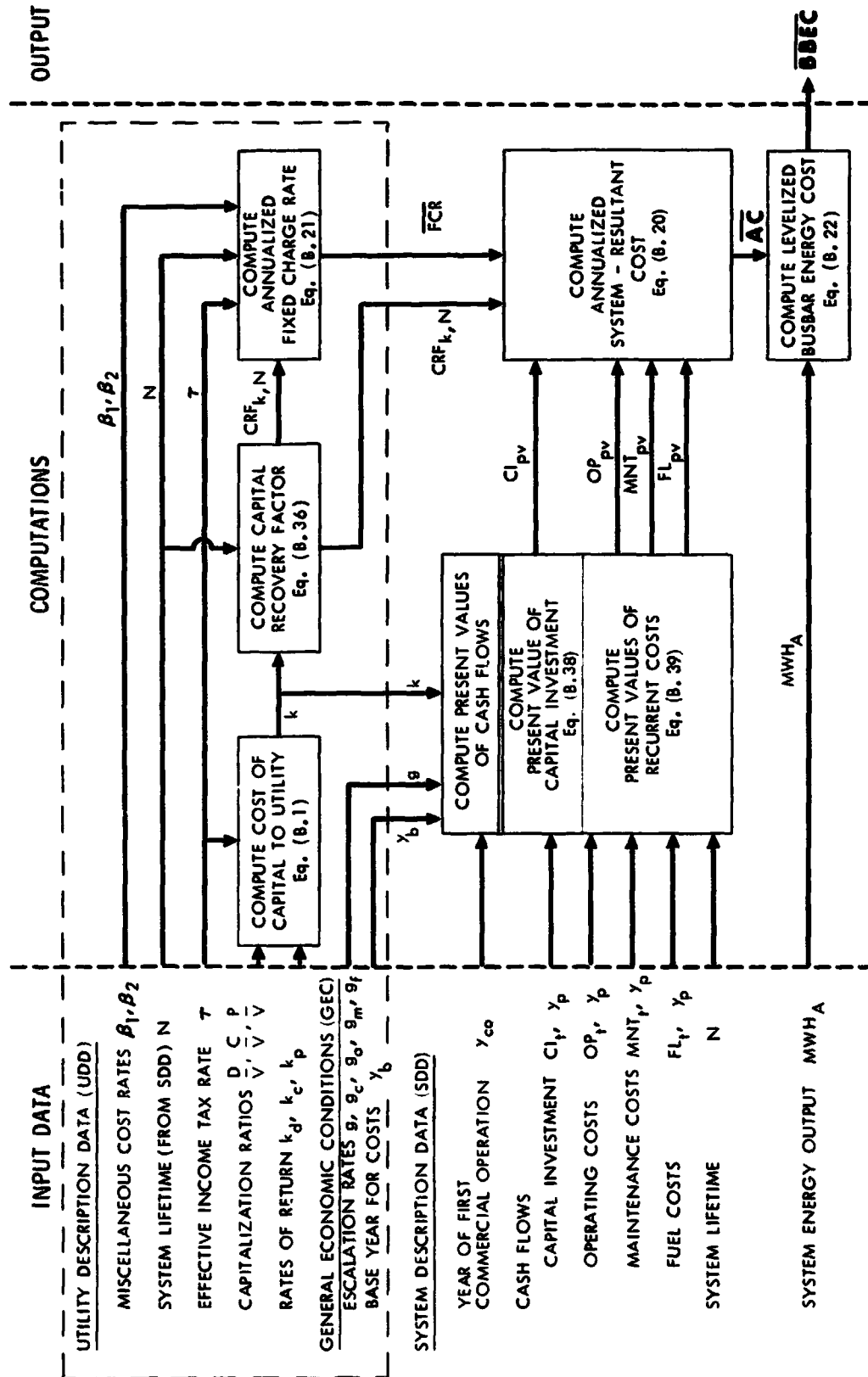


Fig. 2. Structure of Model.

The model is designed to permit sensitivity analyses of the cost of energy to changes in the description of the energy system. A baseline has been specified which consists of a "typical" utility description and a given set of general economic conditions. (This baseline data is contained in Table 1, Table of Nominal Values, in part B.4 of this Section.) For any case which incorporates the baseline utility description and system lifetime (hereafter referred to as a "nominal case"), the results of several important intermediate calculations of the model are predetermined. These implied intermediate results are also included in Table 1, and their use considerably simplifies the use of the model. For instances where reasons exist for perturbing the nominal values, some or all of the intermediate results will have to be recalculated according to the equations presented in Part C of this Section.

B. INPUT DATA

The basic data requirements of the model are a description of the solar energy system, and a description of the utility which will own the energy system. Additional information required is a set of assumptions concerning the escalation rates of various categories of system-resultant costs, and a "start up" date for commercial operation of the system. All cost inputs are to be expressed in 1975 dollars. (This does not mean that contractors are prevented from estimating component costs based on price reductions due to technical breakthroughs, learning curves, etc. It does mean that such estimates should exclude any adjustment for inflation.) The input data will be described in general here, and in detail under Nominal Case below.³

1. System Description Data (SDD)

The energy system is described in terms of its anticipated date of commercial operation, expected operating life, expected output in MWh/year (assumed constant throughout the system lifetime), and the cash flows associated with the capital and operating costs for the system. (A related requirement is the need to report as capital investments any overhaul and/or subsystem replacement necessary to achieve this operating life.) Energy output should

³ The input data, as well as all other variables of the model, are defined in detail in Appendix A, Glossary.

likewise be estimated to consider both the system design (including any expected use of conventional generation as back-up) and the particular application analyzed.

Capital investment flows consist of cash outlays to purchase and install all necessary equipment (including any conventional back-up plants required to maintain a given reliability of the power grid), plus any major maintenance outlays such as for overhaul and/or subsystem replacement. In order to ensure complete and consistent coverage, capital flows are to be calculated and reported according to the procedures detailed in Section IV, Cost Account Structure, for the type of energy system to be analyzed. The result of this step is a distribution of capital outlays which will feed into Eq. (B.38) in the computations phase.

Operating costs, maintenance costs, and fuel costs are assumed to be cost streams that can be described either as constant amounts per year, or as (distinct) series of yearly outlays growing at uniform rates. The cost elements to be included in each of these categories are detailed in Section IV. It should, however, be emphasized that several types of cost are not included in those categories. Major maintenance, as mentioned above, is treated as a capital outlay. Taxes, insurance, depreciation, interest, and return to equity are incorporated in the computations phase of the analysis. These general expenses are not, therefore, to be treated as part of the System Description Data.

2. Utility Description Data (UDD)

The owning utility is described in terms of its capitalization ratios, its rates of return, and its effective marginal income tax rate. Further utility description inputs include two coefficients which serve to allocate constant yearly shares of insurance, property taxes, licenses, and other general expenses to the energy system being analyzed. These shares are computed as proportions of total capital investment in the energy system. The last element of the UDD data block is the system lifetime, which is "copied in" from the SDD block, to be used as the time horizon for financial analysis.

3. General Economic Conditions (GEC)

This block is composed of rates of change of prices, for the economy as a whole and for the various categories of system-resultant costs.

These rates are used to adjust cash flows to dollars that are "current" for the years in which those flows occur, and to adjust the final model result, busbar energy cost, back to base year dollars. Thus, the base year is also specified as part of the nominal case. While the determination of which cost categories are relevant depends on the system to be analyzed, the rates of growth of those costs are determined, at least in part, by price movements in the general economy. This is the reason for identifying GEC as a separate block.

4. Nominal Case

The data inputs and computational steps enclosed in the dashed rectangle surrounding the upper half of Fig. 2 are contractor responsibilities only if it is desired to perturb the nominal case of the "typical" utility and a thirty year system lifetime.⁴ Table 1 contains the values which define the nominal inputs, and the intermediate outputs implied by the nominal inputs. The details of that table are discussed in the next five paragraphs.

System operating lifetime (N) is used as the analysis period for all financial computations. While N determines the financial time horizon, it is determined by considerations of technical design and application environment. Thus the appropriateness of the nominal system lifetime to a particular energy system design must be assessed in light of technical principles. It should be remembered, however, that all systems to be compared must have the same value for N. If a thirty year lifetime is not appropriate, the capital recovery factor (CRF) and the fixed charge rate (\overline{FCR}) must be recomputed for the chosen lifetime. (Note that a change in N does not impact the cost of capital, k.)

The role of the miscellaneous cost rates (β_1, β_2) is to allocate to this project (energy system) a proportional share of such general business expenses as property taxes, license fees, insurance premiums, etc. This share is computed as a fraction ($\beta_1 + \beta_2$) of the investment in the energy system, where investment is measured as a present value of all capital investment flows as

⁴ Escalation rates and the base year do not directly influence the computations inside the dashed rectangle. They are considered part of the baseline information in the interest of standardizing as many of the economic assumptions of the energy system comparison as possible.

Table 1. Table of Nominal Values.

Symbol	Name	Nominal Value
	Nominal Inputs	
<u>Utility Description Data</u>		
N	System Operating Lifetime (from SDD)	30 years
β_1	Annual "Other Taxes" as a fraction of CI_{pv}	0.02
β_2	Annual Insurance Premiums as a fraction of CI_{pv}	0.0025
τ	Effective Income Tax Rate	0.40
D/V	Ratio of Debt to Total Capitalization	0.50
C/V	Ratio of Common Stock to Total Capitalization	0.40
P/V	Ratio of Preferred Stock to Total Capitalization	0.10
k_d	Annual Rate of Return on Debt	0.08
k_c	Annual Rate of Return on Common Stock	0.12
k_p	Annual Rate of Return on Preferred Stock	0.08
<u>General Economic Conditions</u>		
g	Rate of General Inflation	0.05
g_c	Escalation Rate for Capital Costs	0.05
g_o	Escalation Rate for Operating Costs	0.06
g_m	Escalation Rate for Maintenance Costs	0.06
y_b	Base Year for Constant Dollars	1975
Nominal Intermediate Outputs		
k	Cost of Capital to (and internal rate of return in) a "Typical" Utility	0.08
$CRF_{k, N}$	Capital Recovery Factor (8%, 30 years)	0.0888
\overline{FCR}	"Typical" Annualized Fixed Charge Rate	0.1483

of the start of commercial operation. Speculation about future changes in the values of these general expenses is beyond the scope of the model: they are treated as constants over the analysis period.

Because income taxes are an important influence on the effective cost of a business-owned energy system, the income tax rate (τ) is a basic parameter of the utility description. The effective income tax rate shown in Table 1 is less than the legal corporate income tax rate of 48 percent, reflecting an implicit adjustment for investment tax credits and other forms of tax preference.

The importance of including the capitalization ratios and the associated rates of return is largely due to the differential tax treatment accorded returns to equity vis-a-vis returns to bondholders. The values presented in Table 1 are typical of the electric utility industry in the mid-1970's.

Estimates of the course of future prices are always quite speculative, and the escalation rates given in Table 1 are no exception. The constraints considered in selecting those values were quite simple: the prices of capital goods, and of goods and services in general, were assumed to increase at 5 percent per year, while the cost of labor-intensive services (such as operations and maintenance) were assumed to grow 1 percent faster than that. This implies an increase in the relative returns to labor, and also seems consistent with the 8 percent return assumed for low-risk bonds. It is possible to spend a great deal of effort in the hope of producing estimates of price change and interest rates that are "obviously correct." Success in that effort is neither very likely nor, for the purposes of this model, very important. The nominal values should be quite adequate for the production of consistent rank orderings of solar energy systems. For comparisons of solar energy systems with other energy technologies, the possibilities of important changes in relative costs of inputs (i.e., capital vs. fossil fuels) are much greater than for comparisons within a particular technical family. It is important for such applications that the set of interest rate/escalation rate assumptions be considered as a whole, and an internally consistent set of values defined.

C. COMPUTATIONS

This subsection displays the equations referenced in Fig. 2, and presents a brief intuitive discussion of what is going on in each computation block. It is important to note that the intermediate outputs CI_{pv} , OP_{pv} , MNT_{pv} , and FL_{pv} are expressed in current dollars (as of y_{co}). The adjustment to constant dollars is not performed until computing \bar{AC} in Eq. (B.20). (Quantities expressed in constant y_b dollars are printed in bold face throughout this document.) The derivation of the equations is treated thoroughly and rigorously in Appendix B.

1. Cost of Capital (and Internal Rate of Return) to a Utility (k)

One objective of the regulation of utilities is to maintain an equality between the utility's internal rate of return and its cost of capital. That is, the regulating agency tries to set rates so that the utility makes just enough profit to provide competitive rates of return to each category of investor.

The average after-tax cost of capital to a utility is defined by Eq. (B.1):⁵

$$k = (1 - \tau)k_d \frac{D}{V} + k_c \frac{C}{V} + k_p \frac{P}{V} \quad (B.1)$$

The right-hand side of this equation is an after-tax weighted average of the costs (k_d , k_c , k_p) of the various financial instruments used by the utility. The individual terms are the portions that each type of instrument commands in the utility's overall internal rate of return. The $(1 - \tau)$ term reflects the tax-deductibility of interest payments. Thus, with a 40 percent effective tax rate, the real cost to a utility of \$100 in interest payments is only \$60, because that is the amount by which after-tax income would decrease, other things equal, if interest expenses were to increase by \$100. The intermediate output k thus represents the "weighted average after-tax cost of capital." It is used to compute the capital recovery factor in Eq. (B.36), and the present values of cash flows in Eqs. (B.38) and (B.39).

⁵See Eq. (B.1') of Appendix B for the value of k for a publicly-owned utility. Equation numbers correspond to those of the derivations in Appendix B.

2. Capital Recovery Factor ($CRF_{k, N}$)

The capital recovery factor is a standard concept from the mathematics of finance, and represents the uniform annual payment, as a fraction of the original principal, necessary to fully amortize a loan over a specified period of time. The CRF is a function of only two variables: the relevant interest rate, and the specified amortization period. For the purposes of this model, the value of k from Eq. (B.1) is used as the interest rate, and the system lifetime N is used as the amortization period. While values for the CRF appear in all standard financial tables, they are not difficult to compute, and an exact formula obviates the need to interpolate. The standard formula for the CRF is given in Eq. (B.36):

$$CRF_{k, N} = \frac{k}{1 - (1+k)^{-N}} \quad (B.36)$$

The value of $CRF_{k, N}$ is used both to compute the annualized fixed charge rate (\overline{FCR}) in Eq. (B.21), and to annualize the present values of the recurrent costs in Eq. (B.20).

3. Annualized Fixed Charge Rate (\overline{FCR})

The annualized fixed charge rate represents a condensation of all the utility description data into a single number. When \overline{FCR} is multiplied by the present value of capital investment (CI_{pv}), the result is the entire contribution of capital costs, income taxes, and miscellaneous costs to the annualized system-resultant cost. In effect, the \overline{FCR} is a proxy for the utility description data, which interacts with the rest of the model to determine the cost of energy. Thus, the nominal description of a typical utility implies a nominal value for \overline{FCR} as well, and the major work of incorporating the effects of utility ownership into the cost of energy calculation, for the nominal case, has already been performed.⁶ The formula for computing the fixed charge rate is Eq. (B.21):

⁶The interaction of the system description (SDD) and the utility description (UDD) is not strictly a "single point" interface. As discussed above, the system lifetime (N) is an important element of UDD as well. Likewise, the cost of capital (k) will be an important quantity in summarizing the recurrent cash flows.

$$\overline{FCR} = \frac{1}{1-\tau} (CRF_{k,N} - \frac{\tau}{N}) + \beta_1 + \beta_2 \quad (B.21)$$

The resultant value of \overline{FCR} is used as an input to Eq. (B.20) for computing the annualized system-resultant cost.

For the case of a publicly-owned utility, there is no income tax liability (i.e., $\tau = 0.0$) and, as noted in Eq. (B.1') of Appendix B, $k = k'_d$. The expression for the annualized fixed charge rate for a publicly-owned utility is, therefore:

$$\overline{FCR} = CRF_{k'_d,N} + \beta'_1 + \beta_2 \quad (B.21')$$

In any application of Eq. (B.21'), note that the CRF is to be computed using the cost of debt (k'_d) to the public borrower. The primes in Eq. (B.21') reflect two distinctions between the economic environments of publicly- and privately-owned utilities. The replacement of k_d with k'_d reflects the fact that the securities used to finance investment in public power are generally tax-exempt, and therefore sell at lower yields. (A nominal value for k'_d would be 6 percent, as opposed to 8 percent for k_d .) The replacement of β_1 with β'_1 reflects the fact that publicly-owned utilities do not ordinarily pay property taxes. They do, however, make "payments in lieu of taxes," and the nominal value of 0.02 for β_1 is appropriately used for β'_1 as well.

4. Present Value of Capital Investment (CI_{pv})

The present value of capital investment expenditures (CI_{pv}) is the measure used to summarize the total investment in the energy system. All investment outlays are normalized to express their financial significance as of January 1 of the year of first commercial operation. (An important constraint applies to the definition of the CI_t terms themselves — they are to be measured in price year dollars, and are to be compiled in accordance with Section IV, Cost Account Structure.) This normalization consists of an adjustment for escalation of costs between the year of occurrence (of a cash outlay) and the cost reference year, and an adjustment for compound interest.

Since investment outlays are likely to be distributed unevenly, with respect to both timing and size, the terms of the investment distribution are evaluated separately, then summed to find CI_{pv} . The formula for this operation is Eq. (B.38):

$$CI_{pv} = (1 + g_c)^p \sum_t \left[CI_t \left(\frac{1 + g_c}{1 + k} \right)^j \right] \quad (B.38)$$

The terms p and j are defined as:

$$p \equiv y_{co} - y_p, \quad \text{an integer constant;}$$

$$j \equiv y_t - y_{co} + 1, \quad \text{an integer variable.}$$

The y terms are dates which represent the first year of commercial operation (y_{co}), the price year for cost information (y_p), and the year of a given investment outlay (y_t). The rate of escalation for capital goods (g_c) is used to adjust for changes in the price of capital goods between y_p and y_t .⁷ (As a result, CI_{pv} is in current dollars, as of y_{co} . The adjustment back to constant dollars for base year y_b is not performed until Eq. (B.20) for annualized system-resultant cost (\overline{AC} .) The value to be used for k comes from Eq. (B.1). The nominal values for g_c and k are 0.05 and 0.08, respectively, leading to a nominal value for $(1 + g_c)/(1 + k)$ of 0.972.)

5. Present Values of Recurrent Costs (OP_{pv} , MNT_{pv} , FL_{pv})

Present values for streams of recurrent costs (X_t) are computed using Eq. (B.39) (which is discussed thoroughly in part B.6 of Appendix B):

⁷ A full discussion of the adjustments for escalation incorporated in Eqs. (B.38) and (B.39) is contained in part B.4 of Appendix B.

$$X_{pv} = \begin{cases} (1+g_x)^p X_o \left(\frac{1+g_x}{k-g_x} \right) \left[1 - \left(\frac{1+g_x}{1+k} \right)^N \right] & \text{if } k \neq g_x \\ (1+g_x)^p X_o \cdot N & \text{if } k = g_x \end{cases} \quad (\text{B.39})$$

where $p = y_{co} - y_p$
and g_x is the escalation rate for
 OP_t , MNT_t , FL_t , as appropriate.

It is assumed in this methodology that the separate categories of recurrent costs can be represented by (distinct) uniform streams over the system lifetime. This uniformity can be interpreted in either of two senses:

- i. Outlays constant in real terms, growing in dollar amount at the constant rate of escalation.
- ii. Outlays growing at a constant rate in real terms, and thus growing in dollar amount at a larger rate which equals the sum of the constant escalation rate and the rate of real growth.

The values of g_x in the nominal case (and the usage of "escalation" throughout this document) correspond to the first of these interpretations. The formulas incorporating g_x are valid for either interpretation, however, and thus the model may be used for any instance in which some category, or categories, of recurrent costs are expected to uniformly increase or decrease.⁸ The correct value for g_x in Eq. (B.39) is always found as the sum of the escalation rate and the rate of real growth.

⁸ Escalation occurs beginning with the reference year for prices (y_p), while real growth of recurrent costs can only begin as of the start of operations (y_{co}). Consequently, some precautions apply to the exercise of the second interpretation of uniformity above, when $y_p \neq y_{co}$. See footnote 12, in part B.4.4 of Appendix B.

The nominal case defines values for all of the terms of Eq. (B.39) except X_0 , which represents the initial outlay of the given cost stream, and p the number of years from the price year to the start of commercial operation. Thus, the implied nominal value of:

$$(1 + g_x)^p \left(\frac{1 + g_x}{k - g_x} \right) \left[1 - \left(\frac{1 + g_x}{1 + k} \right)^N \right] , \text{ since } (k \neq g_x), \text{ is:}$$

$$(1.06)^p \left(\frac{1.06}{0.02} \right) \left[1 - (0.9815)^{30} \right] = (1.06)^p 22.75$$

$$\text{where } p = y_{co} - y_p.$$

The application of Eq. (B.39) for the nominal case thus reduces to:

$$X_{pv} = (1.06)^p X_0 (22.75) .$$

(In the case of fuel, a 6 percent escalation rate is likely to be an underestimate. In the absence of a firm consensus on the future course of fuel prices, the best approach would be to run sensitivities of any comparison to the escalation rate of fuel. The 6 percent figure could then serve as an appropriately conservative baseline.) The resultant values of OP_{pv} , MNT_{pv} , and FL_{pv} are input to Eq. (B.20) for computing the annualized system-resultant cost.

6. Annualized System-Resultant Cost (\overline{AC})

The present value calculations of Eqs. (B.38) and (B.39) "collapse" their respective cost distributions to single numbers. Each of these present values summarizes its corresponding distribution in terms of the lump sum which, if presently (where y_{co} is defined as the "present") invested at interest rate k , would sustain a flow of withdrawals identical to the original distribution, and end up with a balance exactly equal to zero at the end of N years. To obtain a conceptually correct measure of energy cost (units of cost per unit of energy output), however, cost must be measured in the same flow dimension as energy. The present values computed in Eqs. (B.38) and (B.39) are

annualized from distinct lump sums to a single series of constant annual payments, and converted back to base year dollars, in Eq. (B.20):

$$\overline{AC} = (1+g)^{-d} \left[FCR \cdot CI_{pv} + CRF_{k,N} (OP_{pv} + MNT_{pv} + FL_{pv}) \right] \quad (B.20)$$

where g is the rate of general inflation, and $d = y_{co} - y_b$.

The bold face notation, as mentioned above, denotes that an amount is expressed in constant y_b dollars. \overline{AC} is the annualized system-resultant cost, is measured in (base year) dollars per year, and represents an amount which, if collected in revenues each year, would constitute a revenue distribution with exactly the same present value as the summed present values of all the separate cost distributions analyzed above. \overline{AC} is input to Eq. (B.22) to compute the levelized busbar energy cost.

7. Levelized Busbar Energy Cost (\overline{BBEC})

Levelized busbar energy cost is computed as the quotient of annualized system-resultant cost (\overline{AC}) divided by expected annual energy output (MWH_A). (We have introduced the term "levelized" in place of "annualized" for consistency with utility industry terminology and to denote a "per unit of energy" measure.) This relationship is Eq. (B.22):

$$\overline{BBEC} = \frac{\overline{AC}}{MWH_A} \quad (B.22)$$

Some important requirements apply to the determination of MWH_A in Eq. (B.22). While it is beyond the scope of this document to prescribe detailed conventions for system performance simulations, it is also apparent that any bias in the calculation of MWH_A is passed on to \overline{BBEC} . The value of MWH_A for any given system should reflect the important influences which act to reduce attained and usable output below maximum

theoretical output. To avoid the most common sources of bias, the following general guidelines should be observed:

- i. Expected energy output should be derived from a system performance simulation, based on hourly insolation and weather data over at least one full twelve month cycle.
- ii. In instances where insolation must be estimated on the basis of an "ideal" or "nominal" day, an adjustment must be made to reflect the fact that such insolation is not representative of an average day. That is, a year would be expected to provide less than 365 times the insolation of a nominal day. A repetition of 365 identical days, even if adjusted to "average," would also fail to reflect the effects of sequences of good or bad days.
- iii. It is not necessarily true that all of the insolation available to a solar energy system will in fact be converted and/or used. The value for MWH_A should reflect energy losses or non-use due to saturation of storage or lack of load.
- iv. Another important source of energy losses is system "outage," whether due to scheduled maintenance, or to component failure. Such outages typically reduce system availability (and therefore theoretical system output) by 10 to 15 percent.

All of these influences can be combined in the concept of the "attained capacity factor" (CF_a), which for a solar energy system may range from 20 - 60 percent. The value appropriate for any given system must result from a performance simulation, and is, in any case, interdependent with how the capacity rating (CAP_r) of the system is assigned. This dependence is displayed implicitly in the following relation:

$$MWH_A = CF_a \cdot CAP_r \cdot 8760$$

Because this is, for all practical purposes, a definition of CF_a , it is tautologically true. The message of the above guidelines is that CF_a is almost certainly considerably less than one, and that the value for MWH_A used in Eq. (B.22) must reflect that fact.

Eq. (B.20) can be written as:

$$\overline{\text{AC}} = \overline{\text{FCR}} \cdot \text{CI}_{pv} + \overline{\text{OM}} + \overline{\text{FL}}$$

where, again, bold-face type denotes that cost quantities have been adjusted to base year constant dollars. $\overline{\text{OM}}$ is combined operations and maintenance costs, and the bars over $\overline{\text{OM}}$ and $\overline{\text{FL}}$ denote levelization. Dividing $\overline{\text{AC}}$ by MWH_A leads to the following, which is a standard utility industry expression for levelized busbar energy cost.

$$\overline{\text{BBEC}} = \frac{\overline{\text{FCR}} \cdot \text{CI}_{pv}}{\text{CF}_a \cdot \text{CAP}_r \cdot 8760} + \overline{\text{OM}}^* + \overline{\text{FL}}^*$$

The symbol "*" denotes that the corresponding term has been divided by ($\text{MWH}_a = \text{CF}_a \cdot \text{CAP}_r \cdot 8760$). Since $\overline{\text{AC}}$ is measured in base year dollars, and MWH_A in megawatt-hours, $\overline{\text{BBEC}}$ has the dimension of "base year dollars per megawatt-hour," which is numerically equal to "base year mills per kilowatt-hour." Levelized busbar energy cost is the final output of the model.

SECTION IV

COST ACCOUNT STRUCTURE

The purpose of the present methodology is to provide a means by which the cost effectiveness of alternative designs of solar electric power plant systems can be compared. For such comparisons to be meaningful, it is essential that costs (and energy outputs, as well) be categorized on the same basis for all systems being compared. Even though all cost categories are eventually added together, different categories are affected by different escalation rates and different tax treatments before being combined.

A detailed illustration of a cost account structure is presented in Appendix C. The cost account structure to be used in applying this methodology should be based on the structure used by the Atomic Energy Commission (now ERDA), but extended to include accounts to accommodate cost elements such as solar arrays and energy storage subsystems not found in conventional power plants.

An ERDA/EPRI cost account structure, however, has not yet been published. In the interim, these guidelines should be followed:

- 1) Capital investments should include all costs associated with installation, overhaul, and replacement of capital goods, including architectural and engineering fees, land purchase, site approval expenses, etc. Also included in capital costs are spare parts and contingencies. The system boundary is defined to be the busbar; so, the primary system, power conditioning, energy storage, and conventional back-up subsystems are included in the system. Connection to the power grid and transmission and distribution subsystems are not included. Maintenance vehicles and equipment, if any, are included.
- 2) Operating costs should include administration, office supplies, and so on, but not costs accounted for elsewhere, such as insurance, taxes, or maintenance.
- 3) Maintenance costs should include scheduled maintenance, such as array washing, minor repairs, wages of maintenance personnel,

and so on, and should also include an estimate for unscheduled maintenance, but should not include major overhauls or subsystem replacements. (Overhauls and subsystem replacements are considered capital expenditures.)

- 4) The only fuel costs in solar electric systems are those associated with back-up power subsystems, if any. Other expendables, such as lubricants and fuel for maintenance vehicles, are considered to be maintenance costs.

While not specifically related to the cost account structure, the following points can be reiterated here:

- 5) Expected annual energy output should include consideration of scheduled and unscheduled downtime, diurnal and seasonal variations in insolation (including weather), and energy provided by conventional back-up capacity, if any.
- 6) It is often difficult to determine an appropriate value for allocated costs, such as other (non-income) taxes, insurance premiums, and so on. These costs should be estimated as the marginal costs, to the utility owning the system, which would result from ownership.
- 7) The effective income tax rate used should take into account all applicable investment tax credits (see Appendix E for an alternative approach).

SECTION V
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APPENDIX A
GLOSSARY OF TERMS
AND SYMBOLS USED IN THE METHODOLOGY

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GLOSSARY OF TERMS AND SYMBOLS USED
IN THE METHODOLOGY

α = investment tax credit fraction

The fraction of an investment outlay in a given year that can be claimed as a credit against income tax due for that year. (Used only in Appendix E.)

β_1 = "other" tax fraction

The ratio of all non-income annual taxes to the present value of the total capital investment. As an approximation in the methodology, this fraction is assumed to be a constant, characteristic of the utility that will own the system under evaluation.

β_2 = insurance fraction

The ratio of all insurance premiums to the present value of the total capital investment. As an approximation in the methodology, this fraction is assumed to be a constant, characteristic of the utility that will own the system under evaluation.

τ = effective corporate income tax rate

This is the income tax rate that the firm must apply to gross profit to determine its corporate income tax liability. It is the actual tax rate of 48 percent less an adjustment for applicable tax preference. See "statutory tax rate."

\overline{AC} = annualized system-resultant cost

The annuity, or uniform stream of annual payments over the system lifetime, which has the same present value as the totality of all system-resultant costs.

amortize, amortization

To retire a loan, including all interest due, by a systematic series of replacements. The repayment (or amortization) schedule is computed to result in an outstanding balance of zero at the expiration of the term of the loan.

annualized

Converted into an annuity over the system lifetime. This adjective may also be applied to a factor that facilitates such a conversion, such as the "annualized fixed charge rate." Annualization is denoted in this methodology by placement of a bar over the symbol that represents the present value of the stream of cash flows that is to be annualized. See "annuity."

annualized cost

Equivalent uniform annual cost. See " \overline{AC} ".

annualized fixed charge rate

See " \overline{FCR} ".

annuity

A stream of uniform periodic amounts over a specified period of time. In creating an annuity equivalent to X, the uniform periodic amount is found as the product of X and the appropriate capital recovery factor. See "annualized".

base year

See " y_b ".

\overline{BBEC} = levelized busbar energy cost

That price per unit of energy which, if held constant throughout the life of the system would provide the required revenue, assuming that all cash flow interim requirements or excesses are borrowed or invested at the utility's internal rate of return.

BS_t, BS_{p_v} = bond sales

The revenue derived from selling bonds in period t; or the present value thereof.

CAP_r = rated system capacity

The load for which an energy system is rated. The product of this quantity and the attained capacity factor (CF_a) determine annual system energy output (MWH_A). See "CF_a", "MWH_A".

capacity factor

The ratio of the average load on a machine or equipment, for the period of time considered, to the capacity rating of the machine or equipment. See "CF_a".

capital recovery factor

See "CRF_{k, N}".

capital structure

See "capitalization ratios".

capitalization ratios

The ratios of debt, preferred stock, and common stock equity to the total capitalization of the utility that will own the system under evaluation.

CF_a = attained capacity factor

The ratio of the average load (over a year) on an energy system to the rated system capacity. Estimates of this quantity should reflect weather and load variations, as well as energy losses due to system outage, both scheduled and unscheduled.

CI_t, CI_{p_v} = capital investment

cost of capital, weighted average, after tax

The average effective interest rate faced by the owning utility when it obtains capital. See "k" in "rates of return" and compare with "internal rate of return".

cost, levelized busbar energy

See "BBEC".

cost, life-cycle

See "LCC".

costs, system-resultant

Costs that (would) result from construction of the system, operation and maintenance of the system throughout its lifetime, removal of the system, or any other costs that would not occur if the system were not installed.

CRF_{k,N} = capital recovery factor

The uniform periodic payment, as a fraction of the original principal, that will fully repay a loan, including all interest, in N periods at an interest rate of k per period. (The period used in this methodology is one year.) See Eq. (B.36) for the computation formula.

C/V = common stock fraction

See "capitalization ratios".

d = y_{co} - y_b

The number of years between January 1 of the base year for constant dollars and January 1 of the year of first commercial operation.

discount rate

The interest rate used for computing present values, reflecting the fact that the value of a cash flow depends upon the time at which that flow occurs.

dollars, constant

A unit of measure of value that is invariant with respect to time. In particular, constant dollars and current dollars are synonymous on January 1 of y_b .

dollars, current

A unit measure of value. Due to the operation of inflation, the number of current dollars associated with a fixed real value grows with time at the rate of inflation. Current dollars are thus relevant only to a particular point in time. When specified explicitly, that time is January 1 of y_t .

$DPF_{m,k,n}$ = depreciation factor

The present value of depreciation claims as a fraction of original value. This quantity is a function of the method of depreciation used (m), and the values employed for discount rate (k) and accounting lifetime (n).

D/V = debt fraction

See "capitalization ratios".

equivalent uniform annual cost

See " \overline{AC} ".

escalation

Refers to the change in the price of a specific commodity or service with time. This change is the result of two primary factors: changes in the general purchasing value of money, and changes in the "real" price of the commodity or service which might result from changes in demand, production processes, scarcity of raw materials, or other factors. See "inflation".

escalation rate

See "g".

The fraction per year at which escalation takes place: the difference in prices (from one year to the next) divided by the earlier price.

expected annual energy output

See "MWH_A".

FCR = annualized fixed charge rate

The factor by which the present value of capital investment (CI_{pv}) must be multiplied to obtain the contribution of capital investment to the annualized cost.

financial adjustment

The correction of the initial value of a cash flow (i.e., X_0) for the time effects of expenditure growth and compound interest. Initial values and present values are defined as of the beginning of the year, while cash outflows are assumed to occur at the end of the year. Financial adjustment reflects the influence of escalation and discounting within the year. Thus, $PV \{X_0\} = X_0 (1+g)/(1+k)$. See "t", " X_0 ".

FL_t, FL_{pv} = fuel cost

The recurrent cost of the fuel required to operate the system. This cost category does not include the costs of the fuel used in maintenance vehicles, etc. Those expenses should be reported under MNT or OP, as appropriate.

g = growth rate

The rate of increase of a category of expenditures, which represents the sum of the applicable escalation rate and the rate of "real" growth. Real growth refers to an increase in expenditures or consumption of a larger quantity of a commodity or service, as opposed to an expenditure increase due to an increase in price. (See part B.4.4 of Appendix B for instructions on using g).

GEC = general economic conditions

inflation

Refers to the change in the general purchasing value of money with time. This change can result from changes in the supply of money, changes in patterns of demand, changes in the effectiveness of the utilization of the factors of production, changes in the availability of raw materials, etc. Inflation can be thought of as a weighted average of a very large number of escalation rates.

INS_t = insurance premiums

interest rate

The proportionate change in face value or the proportionate dividend (or some combination thereof) of a real or potential investment during a period of one year.

internal rate of return

The average interest rate which can be obtained by the utility on investments within the company. See "k" in "rates of return". One of the objectives of the regulatory process is to maintain equivalence between the internal rate of return and the "weighted average after-tax cost of capital."

INT_t = interest paid on corporate bonds

$$\underline{j = y_t - y_{co} + 1}$$

The number of years, for purposes of financial adjustment, between December 31 of a particular year and January 1 of the first year of commercial operations.

k = the utility's internal rate of return

Due to the regulatory process, k is also the "weighted average, after-tax cost of capital."

See "rates of return".

k_c = common stockholders' rate of return on investment

See "rates of return".

k_d = interest rate on corporate debt

See "rates of return".

k_p = preferred stockholders' rate of return on investment

See "rates of return".

LCC = life-cycle cost

The present value, as of the year of first commercial operation, of the sum of all system-resultant costs.

levelized busbar energy cost

See "BBEC".

levelized cost

An annualized cost divided by the expected annual energy output, resulting in a cost per unit of energy.

life-cycle cost

See "LCC".

MNT_0 = annual maintenance cost as of y_{CO}

The initial term of the distribution of cash flows for maintenance of the system, expressed as of January 1 in y_{CO} .

MNT_t, MNT_{pv} = maintenance cost

The recurrent cost of maintaining the system, or the present value thereof.

MWH_A = expected annual energy output

The total amount of energy which the system is expected to produce in a year, assumed in the methodology to be the same for each year of the system lifetime. This quantity should result from a system performance simulation, and should reflect energy losses due to system outages and other causes. It is discussed in detail on pp. III-14 and III-15.

N = system lifetime

The number of years that the system under consideration will be in operation before it must be replaced. Major overhauls or replacement of subsystems may be required during this period. It should be noted that the system lifetime is the time horizon of the present system evaluation methodology.

n = accounting lifetime

The asset lifetime used for the purpose of computing depreciation charges. Can be less than or equal to N, the system lifetime assumed for computing amortization charges. (Used only in Appendix E.)

OP₀ = annual operating cost as of y_{co}

The initial term in the distribution of cash flows for operating the system, expressed as of January 1 in y_{co}.

OP_t, OP_{pv} = operating cost

The recurrent cost of operating the system, or the present value thereof.

OT_t = other (non-income) taxes

$$\underline{P = y_{co} - y_p}$$

The number of years from the beginning of the price year to the beginning of the first year of commercial operation.

$$\underline{PDP_t = \text{provision for debt retirement}}$$

Annual allocation to a sinking fund which will be used to retire corporate bonds. The appropriate interest rate is the internal rate of return of the utility that will own the system.

$$\underline{\text{present}}$$

The "present" in "present value" calculations in this methodology is January 1 of y_{co} , the first year of commercial operations.

$$\underline{\text{present value}}$$

The present value of a cash flow is its real value adjusted for the interest that could be earned, or must be paid, between the time of the actual flow and the specified "present" time.

$$\underline{\text{price year}}$$

See " y_p ".

$$\underline{pv(\text{subscript}) = \text{present value subscript}}$$

This subscript denotes the present value of the stream of cash flows represented by the subscripted symbol.

$$\underline{PV \{ \} = \text{present value operator}}$$

This notation implies the present value of the cash flow or flows within the braces.

$$\underline{P/V = \text{preferred stock fraction}}$$

See "capitalization ratios".

rates of return (k_c , k_d , k_p , k)

k = The interest rate which can be obtained or which must be paid by the utility owning the system being evaluated.

k_c = The interest rate which must be provided to the holders of common stock.

k_d = The interest rate which must be paid to the holders of corporate debt.

k_p = The interest rate which must be provided to the holders of preferred stock.

(See "required revenue".)

recurrent costs

Costs associated with the operation of the system that occur throughout the life of the system. See " OP_t ", " MNT_t ", and " FL_t ".

REP_t = return of equity principal

Annual allocation to a sinking fund which will be used to return the principal of common and preferred stockholder's investments. These allocations may be paid directly to the stockholders, reinvested by the system-owning utility, or some combination thereof. The appropriate interest rate for the sinking fund is the internal rate of return of the utility that will own the system.

required revenue

The revenue that must be obtained from the operation of the system being considered so that all costs (including the specified rates of return) can be paid.

return, rate of

See "rates of return".

REV_t , REV_{pv} = revenues from the sale of energy produced by the system

SDD = system description data

SE_t = stock earnings

The return on (but not of) investment to holders of common and preferred stock.

SFF_{k, N} = sinking fund factor

The uniform annual payment, as a fraction of the final balance, that will accumulate to that final balance in N years at an interest rate of k.

sinking fund factor

See "SFF_{k, N}".

SS_t, SS_{p_v} = sales of stock

statutory tax rate

An alternative interpretation of "τ", to be used when tax preference is handled explicitly. (Used only in Appendix E.)

system lifetime

See "N".

system resultant costs

See "costs, system resultant".

t (subscript) = particular year subscript

This subscript denotes the cash flow of the indicated type during the year y_t (treated in this methodology as if it occurred on December 31 of y_t).

TX_t = corporate income taxes

UDD

See "utility description data".

utility description data

This term encompasses the "capitalization ratios" of the firm, the "rates of return" and the tax and insurance rates (see " τ ", " β_1 ", " β_2 ") which the firm must pay. It also incorporates N as the time horizon for financial decisions.

V = total capitalization of the owning utility.

See "capitalization ratios".

value, present

See "present value".

weighted average, after-tax cost of capital

See "cost of capital, weighted average, after tax".

X_0 = initial value of X_t

The cash flow of type X in y_{CO} , expressed as of January 1 in y_{CO} .

X_t, Y_t = the annual amounts of arbitrary streams of cash flows

These symbols are used in Appendix B in equations that apply to any stream of cash flows, especially OP_t , MNT_t , and FL_t .

y_b = base year for constant dollars

Prices computed in the methodology are reported in terms of constant dollars, which correspond to the current dollar price as of January 1 of y_b .

y_{co} = the year of first commercial operation

The methodology assumes that power generation starts on January 1 of y_{co} , and that the first revenues are received on December 31 of y_{co} . January 1 of y_{co} is defined to be the "present" for all present value calculations.

y_p = price year of an expenditure

Prices used in the methodology are supplied as of January 1 of the years for which the most accurate values are available. These years are denoted y_p , and need not be the same for different cost elements for which prices are supplied.

y_t = the year of a particular cash flow

The methodology assumes that the cash flow takes place on December 31 of y_t . The present value of the flow is, however, related to January 1 of y_{co} .

APPENDIX B

DERIVATION OF EQUATIONS USED IN THE METHODOLOGY

APPENDIX B

DERIVATION OF EQUATIONS USED IN THE METHODOLOGY

B.0 INTRODUCTION

The purpose of this appendix is to provide mathematical derivations of the equations used in the methodology to compute comparative cost figures for alternative system designs. The context in which such comparisons are meaningful has been thoroughly discussed in Section II, Approach, and will not be repeated here. The symbols used in this appendix are carefully defined in Appendix A, Glossary.

Section B.1 develops an expression for the life-cycle cost of a utility-owned system, including taxes, interest, and return to equity. This quantity is also identified as the present value of the revenue stream required to recover that cost. Section B.2 develops an expression for the annualized fixed charge rate, which can be used to determine the contribution of total capital investment to the annual "installment" on life-cycle cost. Section B.3 develops an expression for the levelized busbar energy cost, which equals the full annual installment divided by annual output, measured in constant dollars.

Section B.4 contains a discussion of the calculation and properties of present values. Sections B.5 and B.6 contain formulas for computing present values of capital investment and of recurrent costs, respectively, in the presence of cost escalation.

B.1 REQUIRED REVENUES AND LIFE-CYCLE COST

The purpose of this section is to determine what revenue must be provided by the operation of a system to exactly meet all of the financial obligations associated with that system, including taxes, interest, and a specified return to equity holders. It is assumed that the system being considered is owned by a regulated utility. It is further assumed that the construction and operation of the system can be treated as if it were a finite-lived project which the owning utility undertakes for the dual purposes of providing service to its customers and of converting investors' capital into a stream of repayments which include competitive rates of return.

The cash flows associated with this system throughout its life-cycle are illustrated in Figs. B. 1 and B. 2. Cash outflows are represented below the line, cash inflows (revenues) above the line. The "required revenue" is that revenue for which the sum of all of these cash flows is, in some sense, exactly equal to zero. Equal and opposite cash flows that occur at different times, however, do not "sum" to zero, for the earlier flow either accrues or requires the payment of interest. Cash flows at different times can be compared in terms of their "present values" as of a specified point in time. In this analysis, that point is taken to be the start of commercial operations.

In order to compute the present value of a cash flow, the appropriate interest rate must be used. If it is assumed that any temporary imbalance between current revenues and current expenses is made up by, or invested in, the parent company, the appropriate interest rate is the internal rate of return realized by the parent company. Since that company is assumed to be a regulated utility, the internal rate of return is assumed to equal, as a result of the regulatory process, the weighted average after-tax cost of capital, k , defined by Eq. (B.1).

$$k = (1 - \tau)k_d \frac{D}{V} + k_c \frac{C}{V} + k_p \frac{P}{V} \quad (\text{B.1})$$

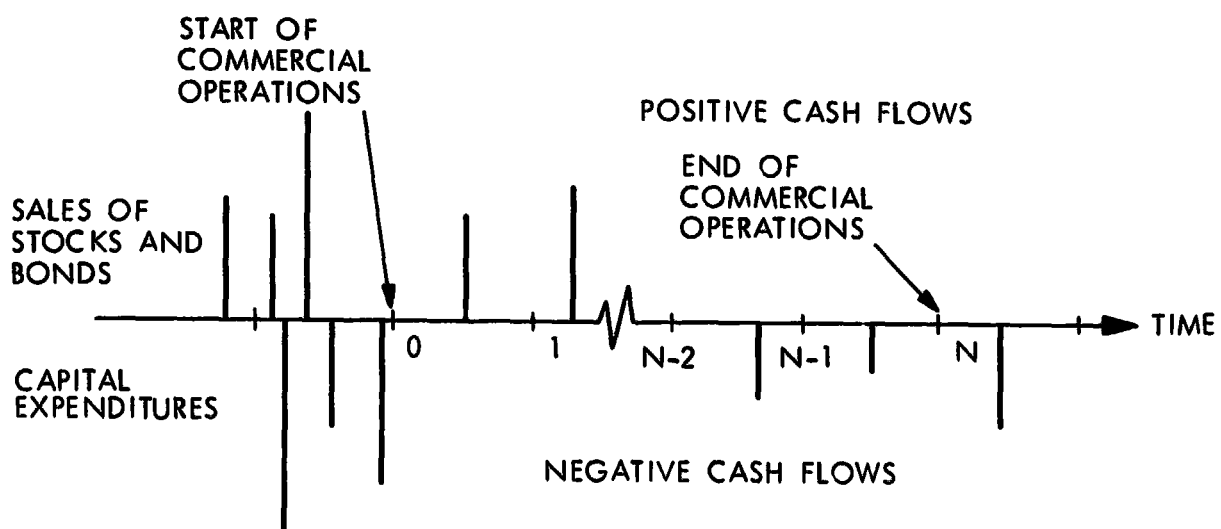


Fig. B-1. Investment Cash Flows.

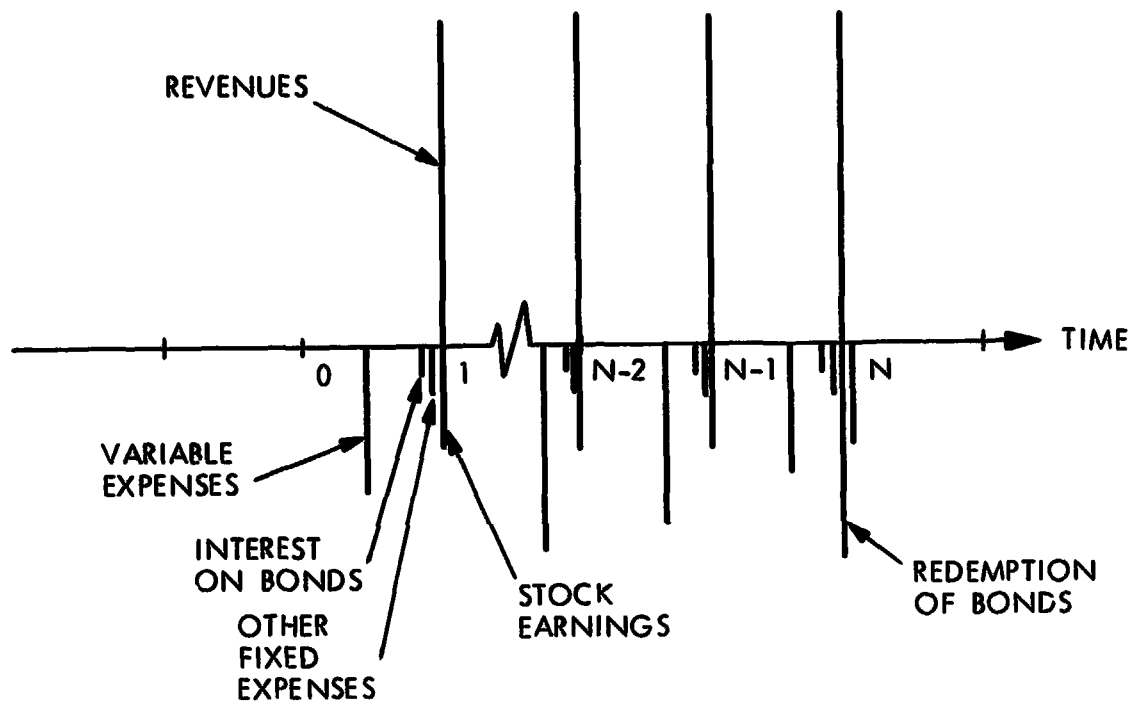


Fig. B-2. Operating Cash Flows.

For the case of a municipal utility, there is no income tax liability, and capitalization is typically debt only (i.e., $D/V = 1$; τ , C/V , and P/V are zero). Thus, k is simply the cost of debt to the public borrower:

$$k = k'_d \quad (\text{B. 1'})$$

The condition that the present value of all positive cash flows must equal the present value of all negative cash flows is given by Eq. (B. 2).

$$\begin{aligned} PV \{REV_t + BS_t + SS_t\} = PV \{CI_t + SE_t + REP_t + INT_t + PDR_t + TX_t + OT_t \\ + INS_t + OP_t + MNT_t + FL_t\} \end{aligned} \quad (\text{B. 2})$$

Not only is the net present value of all cash flows constrained to zero, but the same constraint applies to the investment cash flows by themselves. That is, it is assumed that just enough stocks and bonds sold by the parent

company are allocated to provide the capital needed for this project. This assumption is expressed mathematically by Eq. (B.3).

$$CI_{pv} = BS_{pv} + SS_{pv} \quad (B.3)$$

The income taxes paid for time period t , assumed to be paid at the end of that period, are defined by Eq. (B.4).

$$TX_t = \tau \left[REV_t - (INT_t + DEP_t + OT_t + INS_t + OP_t + MNT_t + FL_t) \right] \quad (B.4)$$

Equations (B.3) and B.4) can be used to restate Eq. (B.2). Omitting the intermediate algebra, the result is Eq. (B.5).

$$REV_{pv} = PV \left\{ \frac{1}{1-\tau} (SE_t + REP_t + PDR_t - \tau DEP_t) + (INT_t + OT_t + INS_t + OP_t + MNT_t + FL_t) \right\} \quad (B.5)$$

The required earnings on stock can be approximated in terms of the shares of CI_{pv} raised by the two kinds of stock, and their known rates of return.⁹

$$SE_t = k_c \frac{C}{V} CI_{pv} + k_p \frac{P}{V} CI_{pv} \quad (B.6)$$

⁹Equations (B.6) and (B.7) rest on the same implicit assumption as Eq. (B.1) — that increases in the capital investment of the firm will be financed by maintaining the same proportional mix of financial instruments as in the overall capitalization ratios.

Similarly, the equivalent uniform annual payment of interest on bonds is given by Eq. (B.7).

$$INT_t = k_d \frac{D}{V} CI_{pv} \quad (B.7)$$

The equity principal must also be returned from revenues derived from the project. The actual disposition of this return is a decision of the parent company: it may choose to add the amount to dividend payments, in which case the equity of the stock will be zero at the end of the project; it may choose to reinvest the amount in other projects, in which case the stock equity will remain constant; or it may choose some combination of these. (The stock equity will increase if the parent company retains and reinvests a portion of the stock earnings in other projects.) Regardless of which decision is taken, the equivalent annual amount that must be allocated to the return of equity principal is given by Eq. (B.8).

$$REP_t = \frac{C + P}{V} CI_{pv} \cdot SFF_{k, N} \quad (B.8)$$

where $SFF_{k, N}$ is the "sinking fund factor," defined as:

$$SFF_{k, N} = \begin{cases} \frac{k}{(1+k)^N - 1} & \text{if } k \neq 0 \\ 1/N & \text{if } k = 0 \end{cases} \quad (B.9)$$

The appropriate interest rate to use in the sinking fund factor is the internal rate of return, which, again due to the regulation of the company, equals the weighted average after-tax cost of capital, k . (It is assumed that these funds are reinvested in other projects, and earn interest at the internal rate of return.)

The project must also be prepared to retire the debt portion of CI_{pv} at the end of the system lifetime. The equivalent uniform annual amount that must be allocated to debt retirement is given by Eq. (B.10).

$$PDR_t = \frac{D}{V} CI_{pv} \cdot SFF_{k, N} \quad (B.10)$$

Straight-line depreciation is assumed in this model.¹⁰ The equivalent uniform annual allowance for depreciation claimed against taxable income is defined by Eq. (B.11).

$$DEP_t = CI_{pv} / N \quad (B.11)$$

It is assumed that other (non-income) taxes and insurance premiums can be approximated as constant multiples of the present value of the total capital investment. These assumptions are stated by:

$$\begin{aligned} OT_t &= \beta_1 CI_{pv} \\ INS_t &= \beta_2 CI_{pv} \end{aligned} \quad (B.12)$$

Substitution of Eqs. (B.6) through (B.12) into Eq. (B.5), followed by some algebraic manipulation, yields Eq. (B.13).

$$\begin{aligned} REV_{pv} = PV \left\{ \frac{1}{1-\tau} \left(k_c \frac{C}{V} + k_p \frac{P}{V} + \frac{C+P}{V} SFF_k + \frac{D}{V} SFF_k - \frac{\tau}{N} \right) CI_{pv} \right. \\ \left. + \left(k_d \frac{D}{V} + \beta_1 + \beta_2 \right) CI_{pv} \right\} + OP_{pv} + MNT_{pv} + FL_{pv} \end{aligned} \quad (B.13)$$

Further manipulation, using the fact that $C + P + D \equiv V$ and the fact that the present value of a uniform series of amounts is equal to that uniform amount divided by the capital recovery factor, produces Eq. (B.14).

¹⁰ See Appendix E for a generalization of the fixed charge rate to consider tax preference, including liberalized depreciation.

$$\begin{aligned}
REV_{pv} = & \left[\frac{1}{1-\tau} \left(k_c \frac{C}{V} + k_p \frac{P}{V} + SFF_k - \frac{\tau}{N} + (1-\tau) k_d \frac{D}{V} \right) + \beta_1 + \beta_2 \right] \frac{CI_{pv}}{CRF_{k,N}} \\
& + OP_{pv} + MNT_{pv} + FL_{pv}
\end{aligned} \tag{B.14}$$

Again, the appropriate interest rate for the capital recovery factor is the internal rate of return, as indicated by the subscript k .

The system life-cycle cost is defined as the present value of the sum of all of the system-resultant costs. Since, as expressed by Eq. (B.3), there is no net investment outside the project, the present value of the revenue stream must just equal the life-cycle cost, as stated by Eq. (B.15).

$$LCC = REV_{pv} \tag{B.15}$$

Equation (B.1) can be used to simplify Eq. (B.14). When that step has been performed, the identity

$$CRF_{k,N} \equiv SFF_{k,N} + k \tag{B.16}$$

(which holds for any interest rate) can be used to further simplify the expression. Finally, using Eq. (B.15), the system life-cycle cost may be expressed, in current (y_{co}) dollars, as Eq. (B.17).

$$LCC = \left[\frac{1}{1-\tau} \left(CRF_{k,N} - \frac{\tau}{N} \right) + \beta_1 + \beta_2 \right] \frac{CI_{pv}}{CRF_{k,N}} + OP_{pv} + MNT_{pv} + FL_{pv}$$

(B.17)

B.2 ANNUALIZED COST

Computation of the present value of a distribution of cash flows "collapses" that distribution to a single number. For a specified interest rate and time origin, and a given distribution of cash flows, this number is unique. The inverse operation, however, is not unique: for any given present value, interest rate, and time interval, there are an infinite number of "equivalent" cash flows.¹¹ A stream of uniform annual amounts over the life of the project, expressed in constant y_b dollars, has been selected to represent the required revenue distribution in this methodology. The result is an annuity, defined as annualized cost (\overline{AC}), with present value equal to LCC, calculated for the same system lifetime. This annuity is obtained by multiplying the present value of required revenues (or equivalently the life-cycle cost) by the capital recovery factor and adjusting back to y_b dollars.

$$\overline{AC} = (1+g)^{-d} \text{REV}_{pv} \cdot \text{CRF}_{k,N} = (1+g)^{-d} \text{LCC} \cdot \text{CRF}_{k,N} \quad (\text{B.18})$$

where g is the general level of inflation, and $d \equiv y_{co} - y_b$.

Using Eq. (B.17), the equivalent uniform annual cost may be expressed as Eq. (B.19).

$$\begin{aligned} \overline{AC} = (1+g)^{-d} & \left\{ \left[\frac{1}{1-\tau} \left(\text{CRF}_{k,N} - \frac{\tau}{N} \right) + \beta_1 + \beta_2 \right] \text{CI}_{pv} \right. \\ & \left. + \text{CRF}_{k,N} \left[\text{OP}_{pv} + \text{MNT}_{pv} + \text{FL}_{pv} \right] \right\} \end{aligned} \quad (\text{B.19})$$

For a firm (or group of firms) with a given economic environment, such that the values for τ , β_1 , β_2 , and k , are constant, the application of Eq. (B.19) to comparison of various candidate energy systems with the same

¹¹ Strictly speaking, this statement is true only if the time interval is greater than one period and money can be infinitely divided.

time horizon, N , can be further simplified by identifying the first term in brackets as the annualized fixed charge rate, \overline{FCR} .

$$\overline{AC} = (1+g)^{-d} \left[\overline{FCR} \cdot CI_{pv} + CRF_{k,N} \left(OP_{pv} + MNT_{pv} + FL_{pv} \right) \right]$$

(B.20)

Comparison of Eq. (B.20), which implicitly defines the annualized fixed charge rate, with Eq. (B.19) gives Eq. (B.21).

$$\overline{FCR} = \frac{1}{1-\tau} \left(CRF_{k,N} - \frac{\tau}{N} \right) + \beta_1 + \beta_2$$

(B.21)

B.3 LEVELIZED BUSBAR ENERGY COST

With all of the system-resultant costs expressed on an annual basis in constant y_b dollars by Eq. (B.20), the last requirement for a measure of cost per unit of energy is an expression for annual energy output. Since the determination of expected annual output of the candidate solar energy systems requires a detailed analysis of the specific design and application, expected annual output is represented here in only a summary fashion, by the symbol MWH_A .

The levelized busbar energy cost, denoted \overline{BBEC} , is that price per unit, expressed in constant y_b dollars, which, if held constant throughout the life of the system, would just satisfy the life-cycle revenue requirement. It can be obtained by dividing the annualized cost, given by Eq. (B.20), by the expected annual energy output. The result is Eq. (B.22).

$$\overline{BBEC} = \frac{\overline{AC}}{MWH_A}$$

(B.22)

As discussed in part III.C.7 of Section III, it is important that MWH_A be a realistic estimate of the annual amount of available, usable energy to be obtained from the system. Thus, in computing MWH_A , theoretical system output must be adjusted for variations in insolation, system availability, and load.

B.4 PRESENT VALUES – CALCULATION AND PROPERTIES

B.4.1 Reference Periods

The methodology presented here treats time as a succession of discrete periods, rather than as a continuum. As is conventional in financial analysis, cash flows corresponding to a particular period are considered to occur at the end of that period. However, since this methodology is intended as an aid to system evaluation, the financial significance of these flows is considered as of the beginning of the first year of commercial operation.

The reference year for cost input data is the year for which the best data are available. The methodology itself undertakes the task of estimating the escalated numerical value of each input as of the beginning of the first year of commercial operation, and adjusts the final output back to constant y_b dollars. This procedure ensures consistency in the method of compounding or discounting, and in the units in which costs are expressed.

B.4.2 The Present Value of a Single Cash Flow

While the reference year for prices is the year for which the best cost data is available, intermediate present value calculations are keyed to the year of first commercial operation, typically several years later than the price year. There are, therefore, three time periods applicable to computing the present value of a given expenditure, identified as:

- y_p the price year
- y_{co} the year of first commercial operation
- y_t the year of a particular expenditure

Combining the escalation and discounting processes into a single expression gives Eq. (B.23) for the present value (expressed in y_{co} dollars) of a single cash flow, where the cash flow, X_t is expressed in y_p dollars.

$$(X_t)_{pv} = X_t \frac{(1+g_x)^{y_t - y_p + 1}}{(1+k)^{y_t - y_{co} + 1}} \quad (B.23)$$

where k is the discount rate, and g_x is the appropriate escalation rate. The "+1" term in each exponent reflects the conventions of beginning-of-the-year measurement of end-of-the-year cash flows. (Thus, X_t should be multiplied by $(1+g_x)/(1+k)$, even if $y_t = y_p = y_{co}$).

Using the following definitions,

$$p \equiv y_{co} - y_p \quad (B.24)$$

$$j \equiv y_t - y_{co} + 1, \quad (B.25)$$

we can rewrite Eq. (B.23) in a more convenient form as Eq. (B.26).

$$(X_t)_{pv} = X_t (1+g_x)^p \left(\frac{1+g_x}{1+k} \right)^j \quad (B.26)$$

B.4.3 The Present Value Operator

The present value operator, used in Section B.1, was introduced to represent the operation of summing the present values of each of the cash flows in a distribution of such flows. Thus, by definition,

$$PV\{X_t\} \equiv X_{pv} \equiv \sum_{t=-\infty}^{\infty} (X_t)_{pv} \quad (B.27)$$

Since Eq. (B.27) is a linear (with respect to the X_t 's) combination of the individual cash flows, the following mathematical properties of the present value operator are immediate:

$$PV\{X_t + Y_t\} \equiv PV\{X_t\} + PV\{Y_t\} \quad (B.28)$$

$$PV\{c \cdot X_t\} \equiv c \cdot PV\{X_t\} \quad (B.29)$$

These properties were used in the derivation of Eq. (B.5), (B.13), and (B.14).

B.4.4 The Present Value of a Growing Series of Amounts

An important class of cost streams dealt with in this methodology are those that grow at a uniform rate. This "uniformity" can be the result of any of several processes, among which are:

- (i) Constant outlays in real terms, growing in nominal terms at a constant rate of escalation.
- (ii) Outlays growing in real terms, and thus growing in nominal terms at a rate which equals the sum of the rate of escalation and the rate of real growth.¹²

In any case, consider a series of cash flows described by Eq. (B.30).

$$X_t = \begin{cases} (1+g_x)^P X_0 (1+g_x)^j & \text{if } 1 \leq j \leq N \\ 0 & \text{otherwise} \end{cases} \quad (B.30)$$

where

X_t = cash flow in year y_t , expressed in y_t dollars

X_0 = cash flow in year y_{c0} , expressed in y_p dollars

g_x = constant rate of growth of expenditures.

¹²If it is desired to model this phenomenon, the user of this methodology must take note of the fact that no real growth in costs will take place prior to y_{c0} , so that the value used for g_x will differ in the two places it is used in Eq. (B.30).

As in Eq. (B.26), the present value of the j^{th} term may be obtained by dividing X_t by $(1+k)^j$. Eq. (B.31) gives the present value, expressed in y_{co} dollars, of the entire cost stream, by using Eq. (B.27), as a sum of a geometric series.

$$X_{pv} = \sum_{t=-\infty}^{\infty} (X_t)_{pv} = (1+g_x)^P X_o \sum_{j=1}^N \left(\frac{1+g_x}{1+k} \right)^j \quad (\text{B.31})$$

The sum can be expressed in closed form as Eq. (B.32).

$$X_{pv} = \begin{cases} (1+g_x)^P X_o \left(\frac{1+g_x}{k-g_x} \right) \left[1 - \left(\frac{1+g_x}{1+k} \right)^N \right] & \text{if } k \neq g_x \\ (1+g_x)^P X_o \cdot N & \text{if } k = g_x \end{cases} \quad (\text{B.32})$$

B.4.5 The Present Value of a Uniform Series of Amounts

The derivation of Eq. (B.14) used the present values of several uniform series of amounts, which is a special case of Eq. (B.32), with $g_x = 0$. Thus, if

$$X_t = \begin{cases} \bar{X} & \text{if } 1 \leq j \leq N \\ 0 & \text{otherwise,} \end{cases} \quad (\text{B.33})$$

then

$$X_{pv} = \begin{cases} \bar{X} \frac{1 - (1+k)^{-N}}{k} & \text{if } k \neq 0 \\ N \cdot \bar{X} & \text{if } k = 0 \end{cases} \quad (\text{B.34})$$

But the multiplier for \bar{X} in Eq. (B. 34) is simply the reciprocal of the tabulated capital recovery factor for a discount rate of k acting over N periods. Thus,

$$\bar{X}_{pv} = \bar{X} / CRF_{k, N} \quad (B. 35)$$

where

$$CRF_{k, N} \equiv \begin{cases} k / [1 - (1 + k)^{-N}] & \text{if } k \neq 0 \\ 1/N & \text{if } k = 0 \end{cases} \quad (B. 36)$$

Equation (B. 35) also supplies the answer to the inverse problem of annualizing a present value – i. e., converting a present value to a uniform stream of cash flows extending over the system life. The equivalent annuity is the product of the present value and the capital recovery factor (as in Eq. (B. 18)):

$$\bar{X} = X_{pv} \cdot CRF_{k, N} \quad (B. 37)$$

B.5 THE PRESENT VALUE OF CAPITAL INVESTMENT, CI_{pv}

Capital investments are distinctive in that they precede first commercial operation – all other categories of expenditure begin at y_{co} . The appropriate adjustment for cash flows prior to the reference period for present value is compounding instead of discounting. The adjustment then reflects interest accrued during construction. It is also quite possible that capital expenditures will occur during the system lifetime (for subsystem overhaul or replacement), and these expenditures should be discounted. Equation (B. 26) in the previous section provides the flexibility for both of these situations. For original investments, the value of j will be negative (or zero) to reflect compound interest; for in-life replacement investments, j will be positive, reflecting discounting. When $y_t = y_{co} - 1$, the value of j will be zero, reflecting the equivalence between the face value of an amount on December 31 and its present value the next day.

The formula for the present value of capital investment, therefore, is given by Eq. (B. 38).

$$CI_{pv} = (1 + g_c)^p \sum_t \left[CI_t \left(\frac{1 + g_c}{1 + k} \right)^j \right] \quad (B. 38)$$

where p and j are defined in Eqs. (B. 24) and (B. 25), CI_t is expressed in y_p dollars, and the summation is performed for all years in which CI_t is not zero for the system being considered. This formula assumes a constant escalation rate for all years and all subcategories of CI. This assumption can be relaxed, if necessary. A "running product" of $(1 + g_c)$ can be kept [see Eq. (B. 40)] for a time-varying escalation rate. If g_c differs among classes of investment expenditure, the formula can be evaluated for each class with a distinct rate. Since present values are additive [see Eq. (B. 28)], the overall CI_{pv} is just the sum of the present values of these classes.

B. 6 THE PRESENT VALUE OF RECURRENT COSTS (OP, MNT, FL)

Recurrent costs are those costs associated with system operation that occur throughout the system lifetime. In particular, the recurrent costs identified in this methodology are the system operating cost during each y_t , denoted OP_t ; the system maintenance cost during each y_t , denoted MNT_t ; and the system fuel cost during each y_t , denoted FL_t .

If these costs can be approximated as growing at a uniform rate, then present values can be obtained from Eq. (B. 32) of the previous section, using the appropriate growth rate. That expression is repeated here as Eq. (B. 39).

$$X_{pv} = \begin{cases} (1+g_x)^p X_o \left(\frac{1+g_x}{k-g_x} \right) \left[1 - \left(\frac{1+g_x}{1+k} \right)^N \right] & \text{if } k \neq g_x \\ (1+g_x)^p X_o \cdot N & \text{if } k = g_x \end{cases} \quad (\text{B.39})$$

where

X is replaced by OP, MNT, or FL, as appropriate

X_o is the cash flow in y_{co} , expressed in y_p dollars

g_x is the appropriate uniform escalation rate

k is the discount rate

N is the system lifetime

If the assumption of a uniform growth rate is not satisfactory, then the present value must be computed by Eq. (B.40), which follows from Eqs. (B.23) through (B.27), and is exactly analogous to Eq. (B.38).

$$X_{pv} = (1+g_x)^p \sum_{j=1}^N \left[X_t \left(\frac{1+g_x}{1+k} \right)^j \right] \quad (\text{B.40})$$

where

X , as in Eq. (B.39), is replaced by OP, MNT, or FL

X_t is the cash flow in y_t , expressed in y_p dollars.

APPENDIX C
COST ACCOUNT STRUCTURE

APPENDIX C

COST ACCOUNT STRUCTURE

The cost account structure to be used in applying this methodology should be that developed by the Energy Research and Development Administration (ERDA), based on the structure used by the Atomic Energy Commission (AEC), extended to include accounts to accommodate cost elements such as solar arrays and energy storage subsystems not found in conventional power plants.

The ERDA cost account structure has not yet been published: interim guidelines are given in Section IV, Cost Account Structure. This appendix gives a detailed illustration of a cost account structure developed for solar thermal power systems by the Aerospace Corporation.

The developed cost estimates should reflect the cost of all hardware and services based on how much that equipment or service would cost as of January 1 of the year for which the most accurate estimate can be made. As an example, if preparing a cost estimate of a turbine generator, the cost estimate that is used should be based on today's cost, not the cost of the equipment based on future purchase prices. The estimate should include the purchase price, set up and assembly, transportation, etc.

The purpose of the cost account structure is to provide a uniform format for reporting costs to ensure that all relevant items are included and that cost estimates for different system designs are categorized in the same fashion, even when obtained from different contractors.

C.1 COST ACCOUNT STRUCTURE – ILLUSTRATION

Each account is identified by a six-character code, as indicated in Figs. C-1 and C-2 and in Table C-1. Data to be supplied for each account include cost estimates, price years, and, if applicable, narratives.

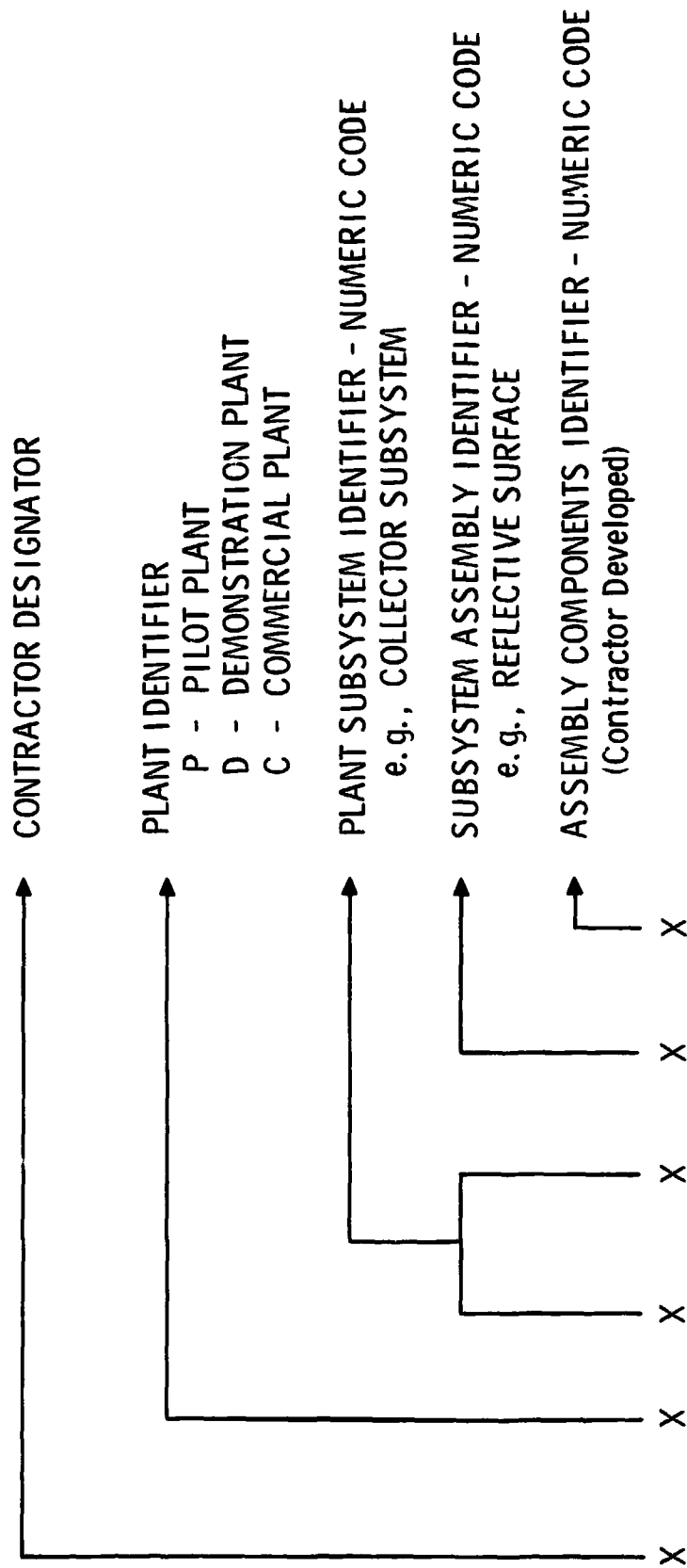


Fig. C-1. Illustrative Cost Account Code.

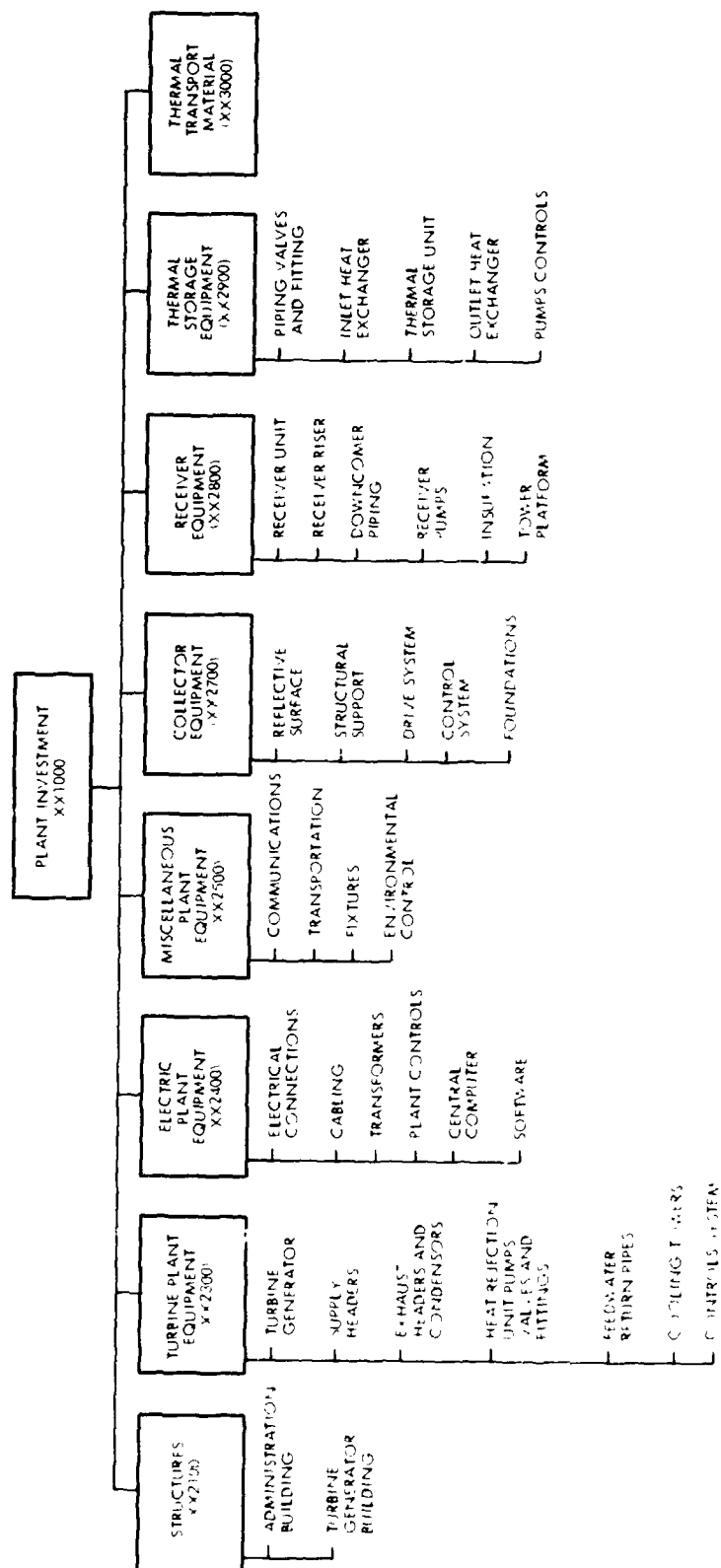


Fig. C-2. Illustrative Capital Investment Account Structure.

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Table C-1. Illustrative Cost Accounts.

<u>XX1000</u>	<p><u>Central Receiver Power Plant</u></p> <p>This account includes all the elements that comprise a central receiver power plant. It contains all the subsystems that directly make up the plant hardware and equipment and also includes land, spare parts, contingencies, and indirect costs.</p>
<u>XX2000</u>	<p><u>Land Acquisition</u></p> <p>This account includes the cost of locating the utilities and buildings on the proposed site, and includes land purchase, surveys, clearing costs, etc. <u>Not</u> included in this element are the costs for preparing the site for a subsystem element (e. g. , site preparation for collector foundation will be allocated to that peculiar subsystem element).</p>
<u>XX2100</u>	<p><u>Structures</u></p> <p>This account includes all structures and facilities required for the conventional portion of power plants, including turbine generator building, administration building, etc. <u>Not</u> included in this account are the costs for structures required for the central receiver towers, collectors, or other special construction facilities.</p>
<u>XX2300</u>	<p><u>Turbine Plant Equipment</u></p> <p>This account includes generator equipment, turbine equipment, instruments and controls, condensing systems, cooling towers and water circulating systems, etc.</p>

Table C-1. Illustrative Cost Accounts (Cont'd).

<u>XX2400</u>	<p><u>Accessory Electrical Plant Equipment</u></p> <p>This account includes power conditioning, switch gear, station service equipment, wiring conditioning, power distribution, controls, computer equipment, software, etc.</p>
<u>XX2500</u>	<p><u>Miscellaneous Plant Equipment</u></p> <p>This account includes transportation, communications, furnishings and fixtures, and environmental control systems.</p>
<u>XX2700</u>	<p><u>Collector Equipment</u></p> <p>This account includes all items related to the central receiver heliostats and includes reflective surfaces, insulation, structural and foundation supports, heliostat drive unit, and any control units.</p>
<u>XX2800</u>	<p><u>Receiver Equipment</u></p> <p>This account includes all items related to the receiver, including the tower. This account includes the receiver unit, receiver support structure, downcomer, riser, control units, and the tower support structure.</p>
<u>XX2900</u>	<p><u>Thermal Storage Equipment</u></p> <p>This account includes the storage equipment in support of the central receiver plant and includes the thermal storage structural unit, heat exchangers, piping, valves, fittings, pump, and control units. Excluded from this account is the heat transport material.</p>

Table C-1. Illustrative Cost Accounts (Cont'd).

<u>XX3000</u>	<u>Thermal Storage Materials</u>
	This account includes only the cost of the heat transport material.
<u>XX4000</u>	<u>Spare Parts</u>
	This account includes all spares utilized for the central receiver power plant during its operational lifetime.
<u>XX4100</u>	<u>Contingency</u>
	This account applies to all direct costs associated with the central receiver power plant.
<u>XX9000</u>	<u>Indirect Costs</u>
	This account contains all cost elements exclusive of the fabrication, checkout, and assembly of the central receiver power plant. It includes any special construction facilities, architect/engineering services, special professional services, training and plant start-up, and any owners' general and administration costs.

APPENDIX D
NUMERICAL ILLUSTRATION

APPENDIX D

NUMERICAL ILLUSTRATION

This appendix contains an example, for illustration only, of the use of the methodology to compute levelized busbar energy cost. While a 200-MW photovoltaic central power plant is used for this example, it should be understood that both the configuration and the costs of this system have been chosen for clarity of illustration, and not as representative of actual systems. The hypothetical system description data (SDD) is contained in Table D.1. Use of the uniform account structure is not illustrated.

The weighted average after-tax cost of capital (k), used as the discount rate in all present value calculations, and as the interest rate (internal rate of return) for all sinking fund calculations, is found from Eq. (B.1):

$$k = (1 - \tau) k_d \frac{D}{V} + k_c \frac{C}{V} + k_p \frac{P}{V} \quad (\text{B.1})$$

Inserting the values for the nominal case (listed in Table 1, page III-6):

$$k = (1 - 0.40) (0.08) (0.50) + (0.12) (0.40) + (0.08) (0.10) = 0.08 \quad (\text{D.1})$$

The capital recovery factor ($\text{CRF}_{k,N}$) is found from Eq. (B.36):

$$\text{CRF}_{k,N} = \frac{k}{1 - (1 + k)^{-N}} \quad (\text{B.36})$$

Inserting the nominal system lifetime (30 years) for N , and the value of k obtained above, the value for the capital recovery factor is:

$$\text{CRF}_{k,N} = \frac{0.08}{1 - 0.09938} = 0.0888 \quad (\text{D.2})$$

**Table D-1. Hypothetical System Description Data for
200-MW Central Power Station.**

Name	Symbol	Value
Year of start of commercial operation	y_{co}	1990
Capital investment cash flows, expressed in 1975 dollars: Land purchases, design engineering etc., incurred 5 years in advance of y_{co} $4 \times 10^6 \text{ m}^2$ of array at \$10/m ² , incurred in the year prior to y_{co} 1×10^6 KWh of energy storage at \$20/KWh, incurred in the year prior to y_{co} 200×10^3 KWpk of power conditioning at \$50/KWpk, incurred in the year prior to y_{co} Miscellaneous capital investment costs, including transportation, installation, array support structures, cabling, etc., incurred in the year prior to y_{co} Array replacement after 15 years of operations, including transportation and installation costs.	CI_{1985} Part of CI_{1989} Part of CI_{1989} Part of CI_{1989} Part of CI_{1989} CI_{2005}	$\$50 \times 10^6$ $\$40 \times 10^6$ $\$20 \times 10^6$ $\$10 \times 10^6$ $\$55 \times 10^6$ $\$60 \times 10^6$
Annual operating expenses for 1990 (as of January 1), expressed in 1975 dollars	OP_o	$\$ 1 \times 10^6$
Annual maintenance expenses for 1990 (as of January 1), expressed in 1975 dollars	MNT_o	$\$ 2 \times 10^6$
Annual fuel expenses for 1990 (as of January 1), expressed in 1975 dollars	FL_o	zero by assumption
System lifetime	N	30 years
Expected annual system energy output: 200 MW at 40% capacity factor for 8760 hours	MWH_A	$7 \times 10^5 \text{ MWh}$

The annualized fixed charge rate ($\overline{\text{FCR}}$) is computed according to Eq. (B.21):

$$\overline{\text{FCR}} = \frac{1}{1 - \tau} \left(\text{CRF}_{k,N} - \frac{\tau}{N} \right) + \beta_1 + \beta_2 \quad (\text{B.21})$$

Using the nominal values for τ , β_1 , and β_2 (0.40, 0.02, and 0.0025, respectively), and the values of N and $\text{CRF}_{k,N}$ from above:

$$\overline{\text{FCR}} = \frac{1}{1 - 0.40} \left(0.0888 - \frac{0.40}{30} \right) + 0.02 + 0.0025 = 0.1483 \quad (\text{D.3})$$

The present value of capital investment (CI_{pv}) is computed according to Eq. (B.38):

$$\text{CI}_{\text{pv}} = (1 + g_c)^p \sum_t \left[\text{CI}_t \left(\frac{1 + g_c}{1 + k} \right)^j \right] \quad (\text{B.38})$$

where

$$p = y_{\text{co}} - y_p$$

and

$$j = y_t - y_{\text{co}} + 1$$

Given the nominal value of g_c for capital costs (0.05), and assuming $y_{co} = 1990$, and capital cost inputs expressed in 1975 dollars (i.e. $y_p = 1975$), the following quantities are constant-:

$$\left. \begin{aligned} (1 + g)^P &= (1.05)^{15} = 2.079 \\ \frac{1 + g_c}{1 + k} &= \frac{1.05}{1.08} = 0.972 \end{aligned} \right\} \quad (D.4)$$

Table D.2 displays the application of Eq. (B.38), incorporating the constants from Eq. (D.4). The entries for CI_t are from Table D.1.

Table D-2. Calculation of CI_{pv} .

t, year	CI_t	j	$(2.079) (0.972)^j CI_t$
1985	$\$ 50 \times 10^6$	-4	$\$116.46 \times 10^6$
1989	$\$125 \times 10^6$	0	$\$259.88 \times 10^6$
2005	$\$ 60 \times 10^6$	16	$\$ 79.19 \times 10^6$
			$CI_{pv} = \sum = \$455.5 \times 10^6$

The present value of capital investment is found to be $\$455.5 \times 10^6$ in y_{co} dollars.

The present values of recurrent costs are computed according to Eq. (B.39), which in this case (since $k \neq g$) can be written:

$$X_{pv} = (1 + g_x)^P X_o \left(\frac{1 + g_x}{k - g_x} \right) \left[1 - \left(\frac{1 + g_x}{1 + k} \right)^N \right] \quad (B.39)$$

As demonstrated in subsection III.C.5, for the nominal case, Eq. (B.39) reduces to

$$X_{pv} = (1.06)^P X_o (22.75) = (1.06)^{15} X_o (22.75) = X_o (54.52) \quad (D.5)$$

The values of OP_{pv} and MNT_{pv} are found by replacing X_o with OP_o and MNT_o (from Table D.1) respectively. The results are presented in Eqs. (D.6).

$$\begin{aligned} OP_{pv} &= (\$1 \times 10^6) 54.52 = \$54.5 \times 10^6 \\ MNT_{pv} &= (\$2 \times 10^6) 54.52 = \$109.0 \times 10^6 \end{aligned} \quad (D.6)$$

The annualized system-resultant cost (\overline{AC}) is computed according to Eq. (B.20):

$$\overline{AC} = (1+g)^{-d} \left[\overline{FCR} \cdot CI_{pv} + CRF_{k,N} (OP_{pv} + MNT_{pv} + FL_{pv}) \right] \quad (B.20)$$

Inserting the appropriate values from above:

$$\begin{aligned} \overline{AC} &= \$(1.05)^{-15} \left[0.1483 (455.5) + 0.0888 (54.5 + 109.0 + 0.0) \right] \times 10^6 \\ \overline{AC} &= 0.48102 (\$82.1 \times 10^6) = \$39.5 \times 10^6 \end{aligned} \quad (D.7)$$

The levelized busbar energy cost (\overline{BBEC}) is computed according to Eq. (B.22):

$$\overline{BBEC} = \frac{\overline{AC}}{MWH_A} \quad (B.22)$$

Inserting the appropriate values from above:

$$\overline{\text{BBEC}} = \frac{\$39.5 \cdot 10^6}{700 \times 10^3 \text{ MWh}} = 56.4 \text{ mills (1975) per KWh} \quad (\text{D.8})$$

The results shown in Eq. (D.8) are expressed in mills per kilowatt-hour, rather than the resultant (and numerically identical) dollars per megawatt-hour, to conform to common usage.

$\overline{\text{BBEC}}$ represents a distribution of energy charges that is constant in nominal terms, i.e., the number of dollars required per MWh of expected energy output is the same every year. The real value, in terms of what those dollars are worth in purchasing power, is not constant (if $g > 0$), however. Thus $\overline{\text{BBEC}}$ must recover more than current dollar costs in the early years of system life to compensate for the erosion of purchasing power affecting later-year revenues (see Fig. 1, p. II-3). The adjustment made above for "constant dollars" serves only to revalue $\overline{\text{BBEC}}$ from y_{c0} dollars to an equivalent number of y_b dollars.

An alternative interpretation of "constant energy charges" is possible – a distribution of charges which has unchanging value in terms of dollars (or mills) of constant purchasing power. Such a distribution of charges would have two key properties – it would satisfy the life-cycle revenue requirement, and it would grow in nominal terms at the rate of general inflation. These properties, plus some earlier results, can be used to describe a distribution of charges of constant real value, denoted as BBEC_t , in terms of the measure we already have, $\overline{\text{BBEC}}$.

Any distribution of revenues that satisfies the life-cycle revenue condition must, by definition, have a present value equal to life-cycle cost. Thus:

$$\text{PV} \{ \text{BBEC}_t \cdot \text{MWH}_A \} = \text{PV} \{ \overline{\text{BBEC}} \cdot \text{MWH}_A \} \quad (\text{D.9})$$

Since both $\overline{\text{BBEC}}$ and MWH_A are constants, the right-hand side of this equation can be written as:

$$\text{MWH}_A \cdot \frac{\overline{\text{BBEC}}}{\text{CRF}_{k, N}} \quad (\text{D. 10})$$

The left-hand side involves taking the present value of a series growing at a uniform rate, precisely the operation for which Eq. (B. 32) was derived above. Incorporating that result and Eq. (D. 10) in Eq. (D. 9)¹³:

$$(\text{BBEC}_0 \cdot \text{MWH}_A) \left(\frac{1+g}{k-g} \right) \left[1 - \left(\frac{1+g}{1+k} \right)^N \right] = \text{MWH}_A \cdot \frac{\overline{\text{BBEC}}}{\text{CRF}_{k, N}} \quad (\text{D. 11})$$

Thus:

$$\text{BBEC}_0 = \frac{\overline{\text{BBEC}}}{G \cdot \text{CRF}_{k, N}} \quad (\text{D. 12})$$

where

$$G \equiv \left(\frac{1+g}{k-g} \right) \left[1 - \left(\frac{1+g}{1+k} \right)^N \right]$$

Thus, for the case evaluated in this Appendix:

$$\text{BBEC}_0 = \frac{56.4}{0.0888 \left(\frac{1.05}{0.03} \right) \left[1 - \left(\frac{1.05}{1.08} \right)^{30} \right]} = 31.8 \text{ mills (1975) per KWh}$$

¹³If $g = k$, Eqs. (D. 11) and (D. 12) must be adjusted in the manner shown for Eq. (B. 32). We assume $p = 0$ in this application of Eq. (B. 32).

The time path of BBEC_t is:

$$\text{BBEC}_t = \text{BBEC}_0 (1+g)^t$$

where $t = 0$ in y_{co} .

If comparison of BBEC_0 with the cost of energy from conventional systems is desired, it should be realized that it is the marginal cost of additional energy production, not the average cost of currently available energy, which is relevant.

APPENDIX E

A GENERALIZATION OF THE ANNUALIZED FIXED CHARGE RATE TO INCLUDE TAX PREFERENCE

APPENDIX E

A GENERALIZATION OF THE ANNUALIZED FIXED CHARGE RATE TO INCLUDE TAX PREFERENCE

The purpose of this Appendix is to produce an expression for the Annualized Fixed Charge Rate (\overline{FCR}) which explicitly considers two common incentives to investment — accelerated depreciation and an investment tax credit. Both of these incentives may be described under the generic heading of "tax preference."

It is possible to generalize the concept of the \overline{FCR} to include tax preference, and at the same time extend the intuitive interpretation of the \overline{FCR} concept. The expression derived in Appendix B for the \overline{FCR} is given by Eq. (B.21), which is repeated below:

$$\overline{FCR} = \frac{1}{1 - \tau} \left(CRF_{k, N} - \frac{\tau}{N} \right) + \beta_1 + \beta_2 \quad (B.21)$$

Equation (B.21) can be rewritten as:

$$\overline{FCR} = CRF_{k, N} \left(\frac{1 - \tau \left[N \cdot CRF_{k, N} \right]^{-1}}{1 - \tau} \right) + \beta_1 + \beta_2 \quad (E.1)$$

The term in parenthesis reflects the influence of taxes on fixed charges. In the absence of taxes (i.e., $\tau = 0.0$), Eq. (E.1) would become $\overline{FCR} = CRF_{k, N} + \beta_1 + \beta_2$, and the fixed charge rate would be the sum of amortization charges and allocated general expenses. The term $\left[N \cdot CRF_{k, n} \right]^{-1}$ represents the present value of straight-line depreciation (over N years) as a fraction of the original value of the asset being depreciated: The uniform yearly depreciation claimed on an asset originally worth CI_{FV} , when that asset is depreciated on a straight-line basis over N years, is:

$$DEP_t = \frac{CI_{pv}}{N} \quad (E.2)$$

The present value of this series of uniform payments is found by dividing Eq. (E.2) by the appropriate capital recovery factor:

$$PV \{DEP_t\} = \frac{CI_{pv}}{N \cdot CRF_{k,N}} = CI_{pv} [N \cdot CRF_{k,N}]^{-1} \quad (E.3)$$

Thus,

$$\frac{PV \{DEP_t\}}{CI_{pv}} = [N \cdot CRF_{k,N}]^{-1} \quad \text{Q.E.D.} \quad (E.4)$$

As we shall be considering alternative methods of depreciation below, it is useful to define the general concept of the "present value of depreciation (by any method) as a fraction of original value." This concept is referred to below as the depreciation factor ($DPF_{m,k,n}$):

$$DPF_{m,k,n} \equiv \frac{PV \{DEP_t\}}{CI_{pv}} \quad (E.5)$$

The m , k , and n subscripts reflect, respectively, the dependence of $PV \{DEP_t\}$ on the method of depreciation, the discount rate, and the accounting lifetime of the asset. The effect of tax-deductible depreciation is to reduce income tax liability by reducing taxable income. Thus the present value of depreciation claims must be multiplied by the income tax rate to arrive at the present value of tax savings.¹⁴ Using the concept of the depreciation factor from above, this present value may be found as:

$$\tau \cdot DPF_{m,k,n} \cdot CI_{pv} \quad (E.6)$$

¹⁴The explicit incorporation of tax preference in the analysis requires a change in interpretation of τ from the "effective tax rate" used in Eq. (B.21). The correct value of τ to use in Eq. (E.6) below is the "statutory tax rate," which can be assumed, for purposes of a nominal case, to equal 0.50.

Expression (E.6) represents a portion of CI_{pv} that is recaptured through tax savings, and thus does not need to be amortized. The implications of this recapture for the \overline{FCR} will be discussed after considering the effect of an investment tax credit.

The introduction of an investment tax credit has the effect of reducing the amount of CI_{pv} that investors have "tied up" in the project. At the end of any year in which an investment outlay has occurred, the utility can claim a credit against its income tax liability equal to a fraction (denoted here as α) of the outlay. Given an investment tax credit equal to α , the effective reduction in "tied-up" present value of a series of investment outlays may be found as:

$$\alpha \cdot CI_{pv} \quad (E.7)$$

where CI_{pv} is computed, as usual, according to Eq. (B.38). This treatment is appropriate because CI_{pv} is based on end-of-year cash flows (see Section B.4 of Appendix B).

Combining expressions (E.6) and (E.7), we find the overall effective amount of investment present value that must be recovered by amortization, after considering both depreciation and the investment tax credit, as:

$$CI_{pv} - \tau \cdot DPF_{m,k,n} \cdot CI_{pv} - \alpha \cdot CI_{pv} = \left(1 - \tau \cdot DPF_{m,k,n} - \alpha\right) CI_{pv} \quad (E.8)$$

If we adjust the result in Eq. (E.8) to reflect the pre-tax revenue necessary to amortize a given amount with after-tax dollars, we arrive at the following quantity:

$$\left(\frac{1 - \tau \cdot DPF_{m,k,n} - \alpha}{1 - \tau} \right) CI_{pv} \quad (E.9)$$

which is simply expression (E. 8) divided by $(1 - \tau)$.¹⁵ If expression (E. 9) is multiplied by the capital recovery factor, and $(\beta_1 + \beta_2) CI_{pv}$ is added to the result, the derived expression represents the annualized fixed charges (\overline{AFC}) resulting from a series of investment outlays with present value CI_{pv} .

$$\overline{AFC} = CRF_{k, N} \left(\frac{1 - \tau \cdot DPF_{m, k, n} - \alpha}{1 - \tau} \right) CI_{pv} + (\beta_1 + \beta_2) CI_{pv} \quad (E. 10)$$

Dividing Eq. (E. 10) by CI_{pv} gives a general expression for the annualized fixed charge rate (\overline{FCR}):

$$\boxed{\overline{FCR} = \frac{\overline{AFC}}{CI_{pv}} = CRF_{k, N} \left(\frac{1 - \tau \cdot DPF_{m, k, n} - \alpha}{1 - \tau} \right) + \beta_1 + \beta_2} \quad (E. 11)$$

It is readily seen that Eq. (B. 21), the standard expression for the \overline{FCR} in the document, is a special case of Eq. (E. 11) for which depreciation is straight-line over the system engineering lifetime ($n = N$; $DPF_{m, k, n} = [N \cdot CRF_{k, N}]^{-1}$), and for which there is no investment tax credit ($\alpha = 0.0$). This is especially evident when Eq. (B. 21) is rewritten into Eq. (E. 1).

It is possible to use Eq. (E. 11) to compute fixed charge rates to correspond to various combinations of depreciation method, accounting lifetime, and investment tax credit. Changes in the level of the investment tax credit are handled by assigning the correct value of the parameter α . Variations in the method of depreciation require alternative expressions for the depreciation factor ($DPF_{m, k, n}$), in which accounting lifetime (n) is a parameters. These

¹⁵Since $0 < \tau < 1$ by assumption, (E. 9) is larger than (E. 8), and by exactly enough to leave (E. 8) for paying taxes. Assume that it is necessary to find an amount of revenue Y , such that after paying taxes of τY , exactly X of revenue remains. This implies:

$$Y - \tau Y = X$$

$$\text{Thus,} \quad Y = X / (1 - \tau)$$

depreciation factors are standard concepts in accounting and in capital budgeting, and are presented here without proofs. In both instances, "n" denotes the asset lifetime for tax purposes, which may be less than the system lifetime (N) used for amortization purposes.

Straight-line depreciation ($DPF_{SL, k, n}$)

$$DPF_{SL, k, n} = \left[n \cdot CRF_{k, n} \right]^{-1} \quad (E.11)$$

Sum-of-the-years-digits depreciation ($DPF_{SD, k, n}$)

$$DPF_{SD, k, n} = \frac{2(n - 1/CRF_{k, n})}{n(n + 1)k} \quad (E.12)$$

Numerical Illustration of the Generalized Fixed Charge Rate

Two major precautions apply to the use of Eq. (E.11) instead of Eq. (B.21). The first concerns the need to substitute the statutory tax rate for the effective tax rate as the value of τ . We assume, for the purposes of a nominal case, that the state income tax rate is 4 percent ($t = 0.04$), and that the federal income tax rate is 48 percent ($T = 0.48$). Since state income taxes are deductible on federal returns, we compute the combined statutory tax rate (τ) as follows:

Assume before-tax net income of Y
state income tax liability = tY
federal income tax liability = $T(Y - tY)$
combined income tax liability as a proportion of $Y \equiv \tau$

$$\tau = \frac{1}{Y} \left[T(Y - tY) + tY \right] = T + t - tT \quad (E.13)$$

For the nominal values assumed above, we find the numerical value of τ as:

$$\tau = 0.48 + 0.04 - (0.48)(0.04) = 0.5008 \quad (E.14)$$

which, for our purposes, rounds to $\tau = 0.50$.

The second precaution pertains to the distinction between the engineering system lifetime (N) used for computing amortization rates, and the asset accounting lifetime (n) used for computing depreciation charges.¹⁶ In general N is used for computing amortization quantities, and n for computing depreciation quantities. (When the CRF appears inside a DPF expression, as it does in $DPF_{SD,k,n}$ below, it is the accounting lifetime that should be used.)

For the purposes of this illustration of the generalized \overline{FCR} , the new input assumptions are sum-of-the-years-digits depreciation for an accounting lifetime of 20 years, a 4 percent investment tax credit, and the 50 percent statutory income tax rate derived above. The full set of required parameter values is:

$$k = 0.08, \quad N = 30, \quad n = 20, \quad \tau = 0.50, \quad \alpha = 0.04, \quad \beta_1 + \beta_2 = 0.0225,$$

implying the following quantities:

$$CRF_{k,N} = 0.0888$$

$$CRF_{k,n} = 0.1019; \quad 1/CRF_{k,n} = 9.818$$

$$DPF_{SD,k,n} = \frac{2(n - 1/CRF_{k,n})}{n(n+1)k} = \frac{2(20 - 9.818)}{20(21)0.08} = 0.6061$$

$$\overline{FCR} = CRF_{k,N} \left(\frac{1 - \tau DPF_{SD,k,n} - \alpha}{1 - \tau} \right) + \beta_1 + \beta_2$$

$$\overline{FCR} = 0.0888 \left(\frac{1 - 0.50(0.6061) - 0.04}{1 - 0.50} \right) + 0.0225 = 0.1392$$

¹⁶ Tax preference with respect to depreciation encompasses the use, for accounting purposes, of artificially shortened asset lifetimes, as well as the expensing of larger-than-proportional charges in the early years of those lifetimes.

This result represents a 6 percent relative decrease from the value for \overline{FCR} used in the nominal case above (see Section III, part 4). Because \overline{FCR} affects only the capital cost portion of \overline{AC} , the relative changes in \overline{BBEC} will always be less than the change in \overline{FCR} .